environmental conservation

The Oil and Gas Industries
National Petroleum Council/1982

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Alton W. Whitehouse, Jr., Chairman
Committee on Environmental Conservation

NATIONAL PETROLEUM COUNCIL

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U.S. DEPARTMENT OF ENERGY

James B. Edwards, Secretary

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry.

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INTRODUCTION

At the request of the Secretary of Energy, the National Petroleum Council (NPC) undertook this comprehensive study, which updates the Council's 1971 report, Environmental Conservation -- The Oil and Gas Industries. In his request, the Secretary stated that "special emphasis should be placed on determining the environmental problems that are most serious and the impact of current environmental control regulations on the availability and cost of petroleum products and natural gas." (See Appendix A for the Secretary's request letter, a description of the NPC, and a roster of the NPC membership.)

To respond to the Secretary's request, the Council established the NPC Committee on Environmental Conservation under the chairmanship of Alton W. Whitehouse, Jr., Chairman of the Board and Chief Executive Officer, The Standard Oil Company (Ohio). The Honorable William A. Vaughan, Assistant Secretary for Environmental Protection, Safety, and Emergency Preparedness, U.S. Department of Energy, was designated Government Cochairman of the Committee. The Committee was assisted by a Coordinating Subcommittee and five task groups: air quality, water quality, land use, hazardous wastes, and synthetic fuels. (See Appendix B for the organization chart and Committee and subgroup rosters).

The study is presented in two parts. An overview of the environmental considerations of oil and gas operations and petroleum product use was published by the NPC in December 1981. These considerations are discussed in more detail in this volume. The Executive Summary and Chapters One and Eight of this volume are from the Overview.

The Secretary concurrently requested the Council to undertake a study of the major issues relating to the development of U.S. Arctic oil and gas resources. The environmental assessment for the Arctic study was critical to both study efforts and was coordinated between both studies. The Executive Summary of the NPC's 1981 report, U.S. Arctic Oil and Gas, is contained in this report as Appendix E. The complete report is available from the National Petroleum Council.

It is appropriate that the Council update the petroleum industry's environmental considerations and concerns at this time. The climate under which the petroleum industry operates today has changed dramatically in the 10 years since the NPC last reported on environmental conservation:

- The energy supply/demand balance has shifted significantly, and there is a newly recognized need for energy security. Achieving energy security requires that environmental concerns be balanced against the need to develop domestic energy supplies.

- For the rest of this century increasing emphasis will be placed on the development of non-oil and non-gas resources, such as coal, nuclear, and synthetic fuels. As a result, environmental considerations should recognize the changing mix of energy supply.

- The petroleum industry has made substantial progress in environmental conservation in the past decade, and the major environmental concerns perceived in the 1970's as arising from the industry are now vastly diminished because pollution sources are under effective control.

- Many of the environmental control strategies in place today are based in large part on environmental legislation and regulation written during the 1960's and 1970's. A re-examination of these control strategies is appropriate, as some may place unnecessary constraints on domestic energy development.

The objectives of this report are twofold: first, to describe current industry operations and explain the facilities and procedures that are used to protect the environment; and second, to focus attention on the specific areas of environmental law and regulation that have directly affected the availability and cost of petroleum products and natural gas.

It is the Council's desire to respond positively to the Secretary's request. While a number of sections may appear to criticize or condemn the key environmentally oriented laws that have been enacted during the decade of the 1970's, many of the laws and regulations discussed in the report are in large part clearly useful and worthwhile. The Council's comments in this regard are intended to be constructive and to express the Council's concern for the high degree of complexity and uncertainty, and the potential for long delays that impede the achievement of balance between the national goals of energy development and environmental protection.

EXECUTIVE SUMMARY

FINDINGS AND CONCLUSIONS

The NPC, in responding to the Secretary's request, sought to identify those environmental issues that will be the focus of continued debate and research in the decade of the 1980's. The NPC also examined the impacts of the petroleum industry on the environment, and the impact of environmental legislative, regulatory, and administrative actions that adversely affect the cost or availability of petroleum products, natural gas, and synthetic fuels. The findings and conclusions reached through this analysis are summarized below. These issues and impacts are discussed in more detail in the following chapters.

Significant Environmental Issues of the 1980's

The following significant environmental issues must be resolved promptly as the nation seeks in the 1980's to balance the goals of energy supply and security with the goals of environmental quality.

- Access to federal lands for the purpose of resource assessment and possible future development
- Delay and uncertainty caused by the complexity of regulatory requirements, including permitting procedures, the number of government authorities involved, and the opportunities for legal intervention by third parties
- Siting of energy facilities, especially production and transportation facilities, that are determined by the location of natural resources
- Incorporation of scientifically acceptable techniques in setting standards, such as National Ambient Air Quality Standards and Water Quality Standards
- Siting and operation of facilities for hazardous waste management
- The ecological and public health effects of, and the control strategies for, the synfuels industry.

There are also a number of issues whose causes are not clearly defined and which are affected by many factors and industries, of which the petroleum industry is only one. These issues are: the ecological and public health effects of, and the control strategies for, acid rain; the CO_2 "greenhouse" effect; groundwater contamination; and indoor air pollution.

To achieve a satisfactory resolution of these issues will require not only the full cooperation of government, industry, and

private citizen groups, but also a commitment to research activities, especially by government and industry segments, that will quantify the impacts, clarify the issues, and determine appropriate solutions to the problems identified.

Industry Impacts on the Environment

As part of its effort to "determine the environmental problems that are most serious" as requested by the Secretary of Energy, the NPC examined impacts of the petroleum industry on the environment. These impacts are a function of the industry's operations (exploration and production; refining; and storage, transportation, and marketing) as well as the use of its products. The NPC's findings with respect to the industry's conventional operations and the projected synfuels industry's operations are summarized below; those resulting from product use are discussed in Chapter Five.

Conventional Oil and Gas Operations

1. Impacts on the environment from current and projected routine conventional petroleum industry operations are largely known and controlled. During the past decade the industry has made significant progress in reducing its impacts on the environment; however, certain long-term possible impacts on the environment are still being investigated.

   - Petroleum industry operations emissions represent only a small fraction of national air emissions. For example, petroleum refining emissions represent only 0.9 percent of the nation's carbon monoxide (CO) emissions, 0.5 percent of total suspended particulates (TSP), 2.8 percent of sulfur dioxide (SO_2), 1.5 percent of nitrogen oxide (NO_x) and 3.9 percent of volatile organic compounds (VOC). In addition, within the refining sector, significant reductions in air emissions per barrel of crude oil run were achieved during the last decade; e.g., a decrease of 68 percent in CO, 50 percent in TSP, 19 percent in SO_2, and 18 percent in NO_x, with no change in VOC.

   - Prevention of Significant Deterioration (PSD) requirements, nonattainment area restrictions, New Source Performance Standards, and provisions for detailed preconstruction review of all major stationary sources of air emissions provide the regulatory framework for controlling air emissions.

   - The refining industry has achieved a greater than 91 percent reduction in the discharge of conventional water pollutants from 1967 to 1979. Additional data indicate that nonconventional pollutants are well controlled and that the existing Best Practicable Control Technology treatment systems remove toxic pollutants to levels barely detectable by the modern analytical techniques, where they are found at all.

- The National Pollutant Discharge Elimination System (NPDES) Permit Program provides regulatory authority for controlling discharges to receiving waters.

- Current industry practices demonstrate that significant improvements in the treatment and disposal of industry-generated wastes have occurred.

- The Resource Conservation and Recovery Act of 1976 (RCRA) provides for regulation of the disposal of hazardous wastes.

- Effects of trace toxic materials in air and water are still being evaluated.

- Past operations and practices that had caused or contributed to adverse environmental impacts have been largely replaced by improved technology and engineering.

- Permitted operational discharges occasionally create minor localized effects, but such discharges cause only negligible overall environmental impacts.

- Some long-term possible problems, such as acid rain and the CO_2 "greenhouse" effect, are not yet understood well enough to determine impacts or to establish final control strategies.

2. Accidental releases of oil and hazardous substances from conventional and routine petroleum industry operations usually do not constitute an irreversible or serious long-term environmental hazard.

   - Major oil spills are more likely to occur in the open ocean. The dilution potential of the open sea and the dispersion, weathering, and loss of toxic constituents, primarily to the atmosphere, make it improbable that oils spilled in deep-sea areas could reach bottom-dwelling (benthic) marine life, much less in toxic amounts. Most oil spills, even those impacting coastal areas, have not had serious long-term effects. Recovery has been rapid in most situations, particularly in relation to marine productivity and populations.

   - Studies following the 1970 Chevron Main Pass Block 41 spill in the Gulf of Mexico, the 1977 Ekofisk oil spill in the deeper waters of the North Sea, and even the very large oil discharge from the Ixtoc blowout in the Bay of Campeche in 1979, indicate that these spills appear to have few or no significant adverse effects in offshore waters.

   - Oil spills create a variety of severe short-term impacts, which can affect commerce, areas of habitation, recreation, and shorelines, particularly when spills

occur in near-shore waters. Near-shore spills and their resulting "chocolate mousse" emulsions can create unsightly messes on beaches and shorelines, cause conspicuous casualties among sea birds, and kill benthic organisms. Especially sensitive to short-term effects are near-shore ecosystems such as coral islands, salt marshes, and mangrove communities.

- Hazardous substance spills do occur occasionally and in some cases cause serious, but temporary, localized effects. Very few materials on the Environmental Protection Agency (EPA) hazardous substance list are used in the petroleum industry. These materials are handled with care, and spills in excess of the appropriate reportable quantity are rare. Where operational spills do occur they are typically contained within tank dikes or removed during wastewater treating operations so that actual harmful releases to navigable waters are minimal.

- Gasoline leaks from service station underground tanks and piping occur throughout the industry and have the potential for serious harm to people, property, and the environment.

3. Groundwater contamination can create serious local problems, and further definition of the extent and degree of risk is required.

   - The petroleum industry is only one of many industries that are concerned with this problem. Nationwide, the extent and risk presented by groundwater contamination from all sources is still being investigated. The prevention and control of groundwater contamination are regulated under the Safe Drinking Water Act and RCRA, as well as many individual state programs.

   - Within the petroleum industry, controls are in place to protect groundwater from the reinjection of produced waters from exploration and production operations, underground cavern storage of petroleum products, and for the detection and cleanup of spills and leaks from petroleum facilities, especially pipelines and service stations.

Synfuels Operations

The projected synthetic fuels industry operations, when assessed on a site- and process-specific basis, are not expected to pose a major threat to the environment. This does not imply that the potential for some long-term chronic effects or regional scale problems has been eliminated. As the industry enters the commercial development stage, more operational data, together with the existing research and development and pilot stage information, will

be available for environmental evaluation and any necessary additional control strategies. In addition, many aspects of the developing synfuels industry are common to conventional technologies, e.g., mining and refining. Environmental effects of synfuels development will continue to be evaluated, and areas of concern that will receive special attention are:

1. Water Quality and Water Availability

   - Evaluation of the impact of mining activities on aquifers

   - Impact of waste disposal areas on groundwater

   - Long-term effects of leachate from in situ and modified in situ shale oil production

   - Water resource development and availability.

2. Air Quality

   - Effect of fugitive dust.

3. Solid Wastes

   - Management and disposal of large quantities of solid wastes.

4. Land Use

   - Closure, revegetation, and/or reclamation of affected land areas.

5. Health and Product Safety

   - The toxicological and ecological properties of synthetic fuels, intermediates and by-products, and wastes.

6. Other

   - Socio-economic impacts of synthetic fuel resource development

   - Identification of special problems from accidental releases of synthetic fuels products.

<u>Environmental Legislative, Regulatory, and Administrative Actions That Adversely Affect the Cost or Availability of Petroleum Products, Natural Gas, and Synfuels</u>

The NPC also examined the impact of environmental legislative, regulatory, and administrative actions that adversely affect the

cost or availability of petroleum products, natural gas, and synfuels. The NPC's findings are summarized below.

1. Land Use

- Past failures to adequately lease offshore government lands have delayed resource assessment, exploratory drilling, and production. Withdrawals and extended classification determinations of onshore government lands have also inhibited resource assessment and potential development of such areas.

- Coastal Zone Management consistency review results in delays of leasing and exploration activities.

- The designation of Marine Sanctuaries can prevent oil and gas activity in or near designated sanctuaries.

- The Endangered Species Act can prevent or delay development of energy and water resources.

2. Air Quality

PSD increments limit allowable new growth, especially in or near Class I areas.

- Construction of modified refining and new transportation and production facilities in nonattainment areas may be banned if the State Implementation Plans are not approved.

- There is an insufficient pool of offsets in some nonattainment areas to meet permit requirements for new or modified sources of emissions.

- The application of Class I visibility protection criteria to adjacent areas, as embodied in the integral vista concept, can restrict resource development.

- Outer Continental Shelf (OCS) air regulations pertaining to attainment, and PSD increments could inhibit OCS oil and gas development.

- Lack of guidance in determination of Best Available Control Technology and Lowest Achievable Emission Rate, and the frequent disagreement between and among federal, state, and local agencies and the industry over the level of controls contribute to delays in processing and issuing permits.

- Monitoring and data gathering regulatory requirements are frequently excessive, costly, and time-consuming; in combination, these requirements can result in lengthy delays of new and expanded energy sources.

- Modeling requirements are expensive and time-consuming, and, more importantly, the air quality predictions are usually conservative. They can lead to delays and costly restrictions on new and modified sources that may be unnecessary to protect air quality or achieve environmental benefits.

- Automotive exhaust emission restrictions, particularly those that prevent the use of alkyl lead compounds in automotive fuels, reduce the amount of transportation fuel that can be obtained from a given quantity of crude oil.

- Restrictions imposed by many local jurisdictions on the sulfur content of petroleum fuels have changed supply patterns for heavier fuels in particular and have increased the price for suitable fuels in low-sulfur fuel regions.

- Guidance documents prepared by EPA such as the Control Techniques Guidelines have been interpreted all too often to be standards or regulations by the states or EPA regions. This has frequently led to more stringent regulations and/or permit limits on industry, with resulting higher costs, than were necessary to satisfy air quality requirements.

3. Water Quality

Unreasonable delays in issuance of NPDES permits for oil and gas exploratory drilling operations in almost every offshore area of the United States have raised compliance costs and delayed efforts to find oil and gas The EPA's recently initiated policy on issuing general NPDES permits could alleviate the delay problem.

- Present wetlands policy has delayed issuance of dredge and fill permits by the U.S. Army Corps of Engineers.

- The EPA policy of effectively requiring state agencies to adopt the EPA water quality criteria as state standards frequently could place unrealistic limits on wastewater discharges from both new and existing facilities. The EPA water quality criteria on some toxic pollutants are based on very limited data and some criteria are below the detection limits of current analytical techniques.

- Failure of EPA to issue petroleum refining effluent guidelines within the deadlines set by court order and statute has introduced uncertainty into the regulatory process This uncertainty exacerbates the problems faced by refiners who need sufficient lead time to design and install wastewater treatment equipment to

comply with the July 1, 1984, deadline, especially if additional equipment is necessary. In addition, EPA's proposed guidelines are overly severe and fail to consider industry progress and performance in water pollution control.

4. Hazardous Wastes

- Regulation of hazardous waste and waste management facilities has not been based on the degree of hazard presented to human health and the environment by the specific wastes being stored. As a result, unduly restrictive and costly measures may be required.

- Complex technical and societal problems of siting new hazardous waste management facilities will hamper the nation's ability to adequately dispose of its waste. If local sites are unavailable, transportation of hazardous wastes to remote sites will be costly and may present a greater risk to the environment.

SUMMARY OF COSTS -- PAST AND FUTURE

Costs of environmental regulations to the petroleum industry have been in the past and will be in the future a significant component of industry expenditures. Expenditures to protect environmental quality and human health are recognized to be a necessary cost of doing business. It is also important to recognize, however, that environmental standards more stringent than those necessary to protect the environment and human health impose higher industry capital and operating costs and, ultimately, higher product costs to the consumer. Cost is, of course, just one of the factors in the achievement of a balance between environmental protection and energy development and security.

In part, these higher costs result from overly conservative and protective control strategies, some of which are not based on valid scientific studies that have been subject to peer review. The NPC believes that a better balance is needed, and that control strategies should be developed based on valid scientific studies that have been subject to peer review.

In addition to these higher identified costs are the significant, but difficult to quantify, "costs of delay" that result from delays in the permitting process. The NPC believes that steps are needed to improve the permitting process in order to facilitate domestic oil and gas resource development.

A recent petroleum industry expenditure survey (representing 70 percent of refining capacity) by the American Petroleum Institute indicates that expenditures for environmental protection during the 1971-1980 period totaled $21.1 billion as spent. A 1980 Battelle study forecasts the capital expenditures of the conventional petroleum industry for environmental protection (excluding the impact of

RCRA) to be $57 billion (constant 1979 dollars) for the 1970-1990 period, with annual operating costs of about $6 billion (constant 1979 dollars) per year in the latter half of the 1980's. For additional details and a breakdown of the expenditures, see Tables 6 through 14 in Chapter One.

In order to put these expenditures and forecasted costs in perspective, Table 15 of Chapter One shows the estimated incremental environmental control expenditures for both the public and private sectors in the United States for the 1979-1988 period, as projected by the Council on Environmental Quality in 1980. During the 10 years from 1979 through 1988, total spending in response to the federal environmental quality regulations is expected to reach $518.5 billion.

The estimated breakdown of this spending by environmental program is presented below:

- Air -- $300 billion (58 percent)
- Water -- $170 billion (33 percent)
- Land Reclamation -- $15.3 billion (3 percent)
- Hazardous Waste Management -- $15.4 billion (3 percent)
- Control of Hazardous Substances -- $8.2 billion (2 percent)
- Noise Control -- $6.9 billion (1 percent).

These levels of environmental expenditures by the petroleum industry as well as other public and private segments within the United States evidence a continuing commitment to environmental quality.

CHAPTER ONE

GENERAL CONSIDERATIONS REGARDING ENVIRONMENTAL CONSERVATION

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GENERAL CONSIDERATIONS REGARDING ENVIRONMENTAL CONSERVATION

INTRODUCTION

Before examining the issues concerning the petroleum industry and the environment, it is helpful to place into perspective the future direction of the industry. The volume and components of energy production and consumption have a direct bearing on the nature and extent of the environmental protection mechanisms necessary.

Some of the basic environmental laws were passed in the 1960's and early 1970's, when the price of crude oil was extremely low and the domestic economy and energy consumption were believed to be continuing to expand unchecked. In addition, state and local governments were experiencing difficulties in meeting their constituents' needs resulting from that growth. A national concern developed that state and local government entities could not properly manage the complex responsibilities of environmental protection, that federal protection and standards were required, and legislation to that effect was enacted.

The energy demand growth expectation was linked directly to the expected Gross National Product (GNP) growth, with some early 1970's estimates projecting that 1985 U.S. energy consumption would be as high as 130 quadrillion British thermal units (Btu's). (Current estimates are on the order of 83 quadrillion Btu's or less.) High energy consumption projections imply higher levels of emissions.

The early 1970's energy projections were proven wrong by events of that decade. Figure 1 compares the actual energy consumption during the 1970-1980 period with energy demand forecasts prepared by the National Petroleum Council (NPC) at the beginning, midpoint, and end of the decade. The Organization of Petroleum Exporting Countries crude oil price increases and the embargo of 1973-1974 by the Arab member countries, together with the cutoff of Iranian imports into the United States in December 1978 and other economic and political events, dramatically altered the energy consumption patterns in the United States and changed the public perception of energy and its position in the economy.

To place the petroleum industry's future contributions to U.S. energy supply in perspective, a brief summary of a recent supply/demand projection through 1990 is presented. Following that section is a history and description of the major environmental laws concerning the oil and gas industry and a discussion of the costs of environmental control to the petroleum industry.

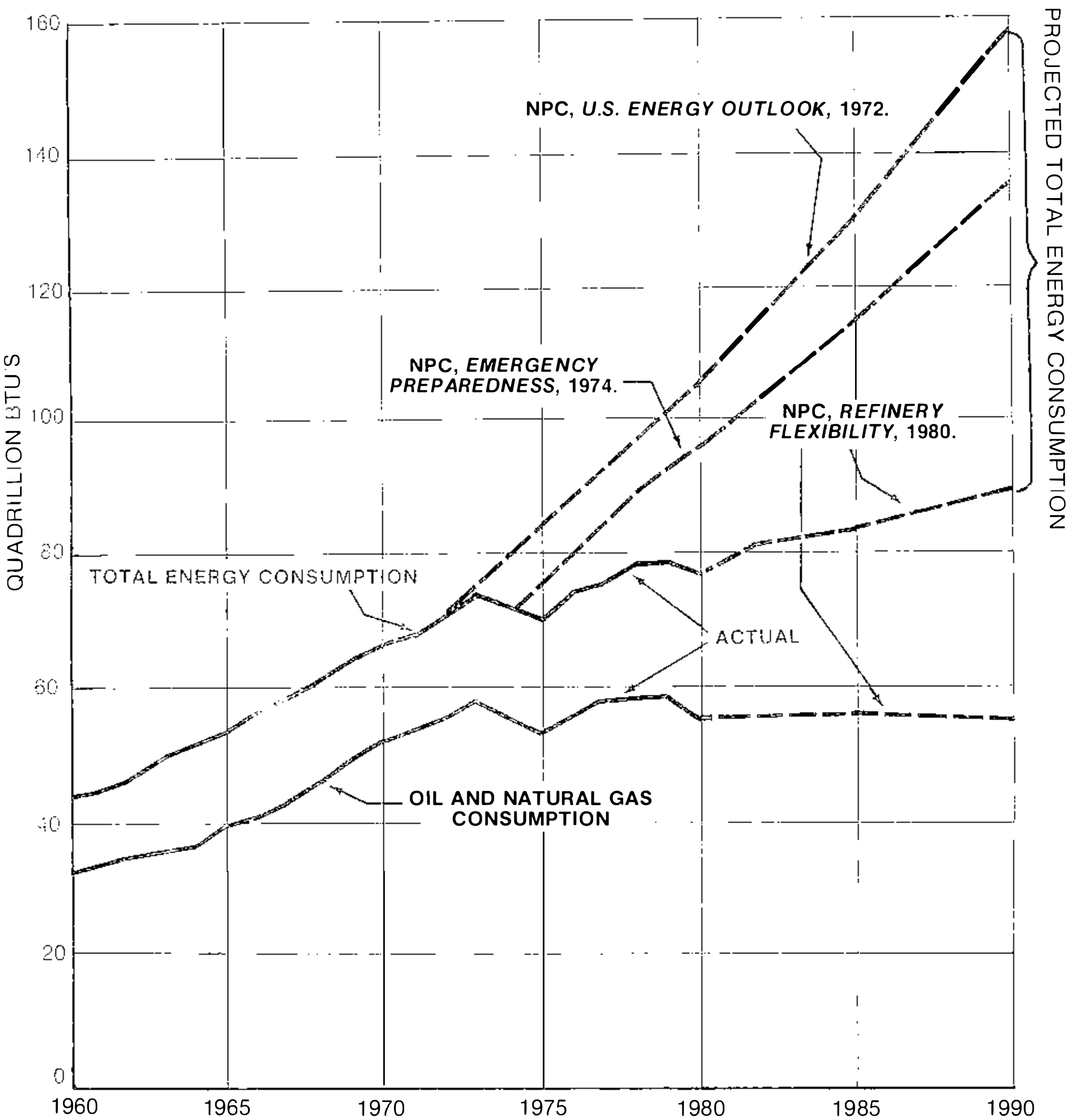


Figure 1. Comparison of Actual Energy Consumption with Projections.

NOTE: Actual data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Projected data from National Petroleum Council, as cited.

U.S. ENERGY AND PETROLEUM SUPPLY/DEMAND PROJECTIONS

The following projections were drawn from the Low Demand Case of the NPC's 1980 report, Refinery Flexibility. These projections present the "adjusted average" balances of the lowest quartile responses to a 1980 NPC survey of 35 organizations that regularly prepare such forecasts. The NPC believes that these projections present a representative assessment of the trend of future energy supply/demand in this country, although many observers of the energy situation are projecting even lower levels of U.S. energy demand in 1990.

I. U.S. Total Energy Consumption

During the decade of the 1980's, U.S. energy consumption is expected to experience a 1.5 percent annual rate of growth, while comparable real GNP growth is expected to be 2.1 percent per year. During the 1960's and 1970's the annual average increase in consumption was 4.2 percent and 1.3 percent, respectively, with annual average GNP growth of 3.8 percent and 3.3 percent. Total U.S. energy consumption is expected to increase from 76.3 quadrillion Btu's in 1980 to 88.6 quadrillion Btu's in 1990. Figure 2 and Table 1 present these data, as well as the historical and projected total energy consumption per dollar of real GNP.

Figure 3 and Table 2 present a comparison of U.S. energy consumption by type of energy. Oil and gas combined are expected to constitute a declining absolute volume, as well as a decreasing percentage of the projected total U.S. energy consumption. Thus, the projected consumption of oil and gas is expected to decline by 2.4 percent in this decade, compared to the 58.3 percent increase from 1960 to 1970 and the 6.4 percent increase from 1970 to 1980. The percentage of oil and gas consumption to total energy consumption is also expected to decline in this decade, from 71.6 percent of total energy consumption in 1980 to 60.1 percent in 1990.

TABLE 1

U.S. Energy Consumption and Gross National Product -- 1960-1990*

	Total Energy (Quadrillion Btu's)	Gross National Product (Billion 1972 Dollars)
Actual 1960 Data	44.10	737
Actual 1970 Data	66.83	1,075
Actual 1980 Data	76.26	1,481
1985 Projection	82.92	1,630
1990 Projection	88.59	1,820
	Annual Growth Rate (Percentage)	
Actual 1960-1970 Data	4.2	3.8
Actual 1970-1980 Data	1.3	3.3
1980-1985 Projection	1.6	1.9
1985-1990 Projection	1.3	2.2
1970-1990 Projection	1.4	2.7

*Actual energy consumption data from Energy Information Administration, 1980 Annual Report to Congress, Volume II. Actual Gross National Product data from U.S. Department of Commerce, Bureau of Economic Analysis. Projected data from National Petroleum Council, Refinery Flexibility, 1980.

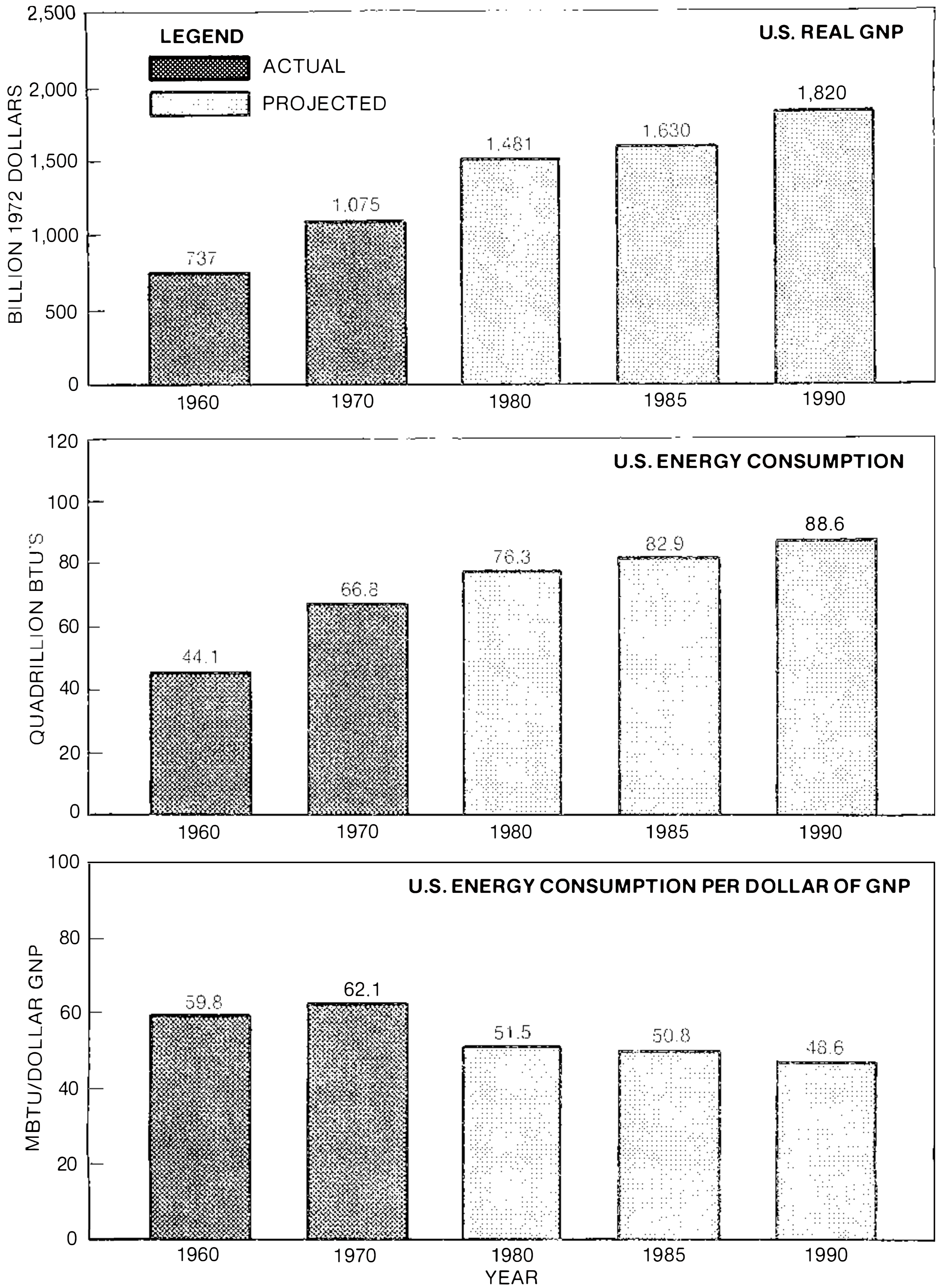


Figure 2. U.S. Gross National Product and Energy Consumption Projections—1960-1990.

NOTE: Actual energy consumption data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Actual Gross National Product data from U.S. Department of Commerce, Bureau of Economic Analysis. Projected data from National Petroleum Council, *Refinery Flexibility*, 1980.

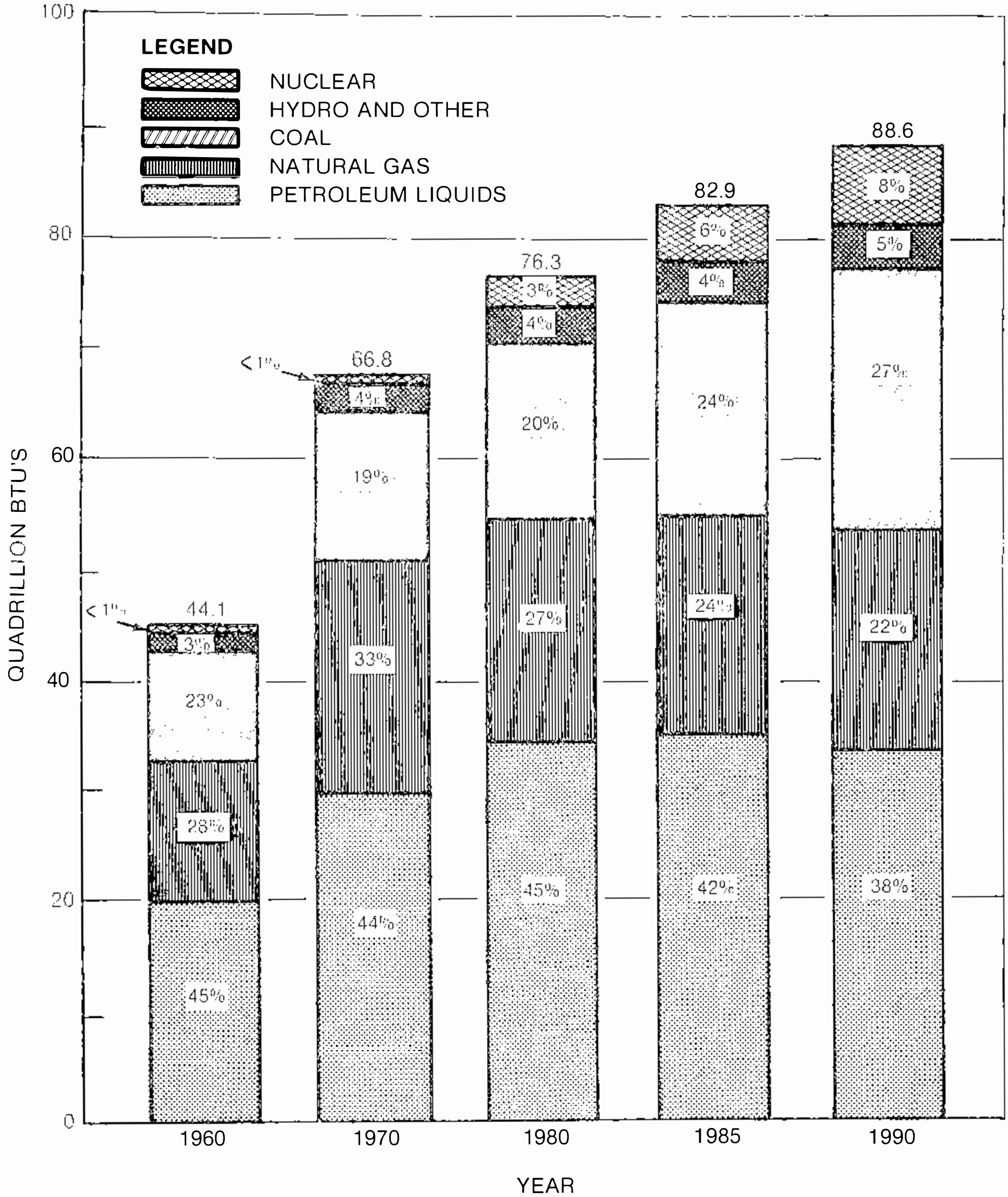


Figure 3. U.S. Energy Consumption by Type of Energy—1960-1990.

NOTE: Actual data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Projected data from National Petroleum Council, *Refinery Flexibility*, 1980. Percentages are share of total consumption in year shown.

TABLE 2

U.S Energy Consumption -- 1960-1990*

	Actual 1960†	Percentage of Total	Actual 1970†	Percentage of Total	Actual 1980†	Percentage of Total	Projected 1985†	Percentage of Total	Projected 1990†	Percentage of Total
Petroleum	20.0	45.3	29.5	44.2	34.2	44.8	34.9	42.1	33.7	38.0
Natural Gas	12.4	28.1	21.8	32.6	20.4	26.8	19.5	23.5	19.6	22.1
Subtotal	32.4	73.4	51.3	76.8	54.6	71.6	54.4	65.6	53.3	60.1
Coal	10.1	23.0	12.7	19.0	15.7	20.6	19.5	23.5	24.2	27.3
Nuclear	0.0	<1	0.2	<1	2.7	3.5	5.3	6.4	7.0	7.9
Hydro and Other	1.6	3.6	2.6	3.9	3.2	4.2	3.6	4.3	4.1	4.6
Total	44.1	100.0	66.8	100.0	76.3	100.0	82.9	100.0	88.6	100.0

*Actual data from Energy Information Administration, 1980 Annual Report to Congress, Volume II. Projected data from National Petroleum Council, Refinery Flexibility, 1980.

†Quadrillion Btu's.

II. U.S. Petroleum Supply

Figure 4 and Table 3 compare the supply projections of domestic liquids production (crude oil and condensate and natural gas liquids) with petroleum imports to 1990. The 1980 NPC survey indicated that conventional liquids production is projected to decline sharply, from 10.2 million barrels per day (MMB/D) in 1980 to 8.5 MMB/D in 1990. Synthetic crude oil production is projected to increase from zero in 1980 to 0.5 MMB/D in 1990.

Total U.S. imports (crude and unfinished oils, and finished products and natural gas liquids) are expected to increase from 6.8 MMB/D in 1980 to 7.5 MMB/D by 1990, with approximately the same crude oil/product proportions as in 1980 -- three-quarters crude oil, one-quarter products.

TABLE 3

U.S. Petroleum Supply -- 1960-1990*
(Millions of Barrels Per Day)

	Actual			Projected	
	1960	1970	1980	1985	1990
Domestic Production					
Crude Oil and Condensate	7.1	9.6	8.6	8.0	7.5
NGL	0.9	1.7	1.6	1.2	1.0
Syncrude Production	0.0	0.0	0.0	0.1	0.5
Subtotal	8.0	11.3	10.2	9.4	9.0
Imports					
Crude and Unfinished Oils	1.0	1.3	5.2	6.0	5.7
Products and NGL	0.8	2.1	1.6	1.7	1.8
Subtotal	1.8	3.4	6.8	7.7	7.5
Processing Gain and Stock Change	0.2	0.3	0.6	0.5	0.5
Total Petroleum Supply	10.0	15.0	17.6	17.6	17.0

*Actual data from Energy Information Administration, 1980 Annual Report to Congress, Volume II. Projected data from National Petroleum Council, Refinery Flexibility, 1980. Columns may not add due to rounding.

III. U.S. Petroleum Demand

The projected 1990 total U.S. petroleum demand presented in Figure 5 and Table 4 reflects the conservation of resources and the shift in energy raw materials resulting from the political and economic events of recent years. Total U.S. petroleum demand is

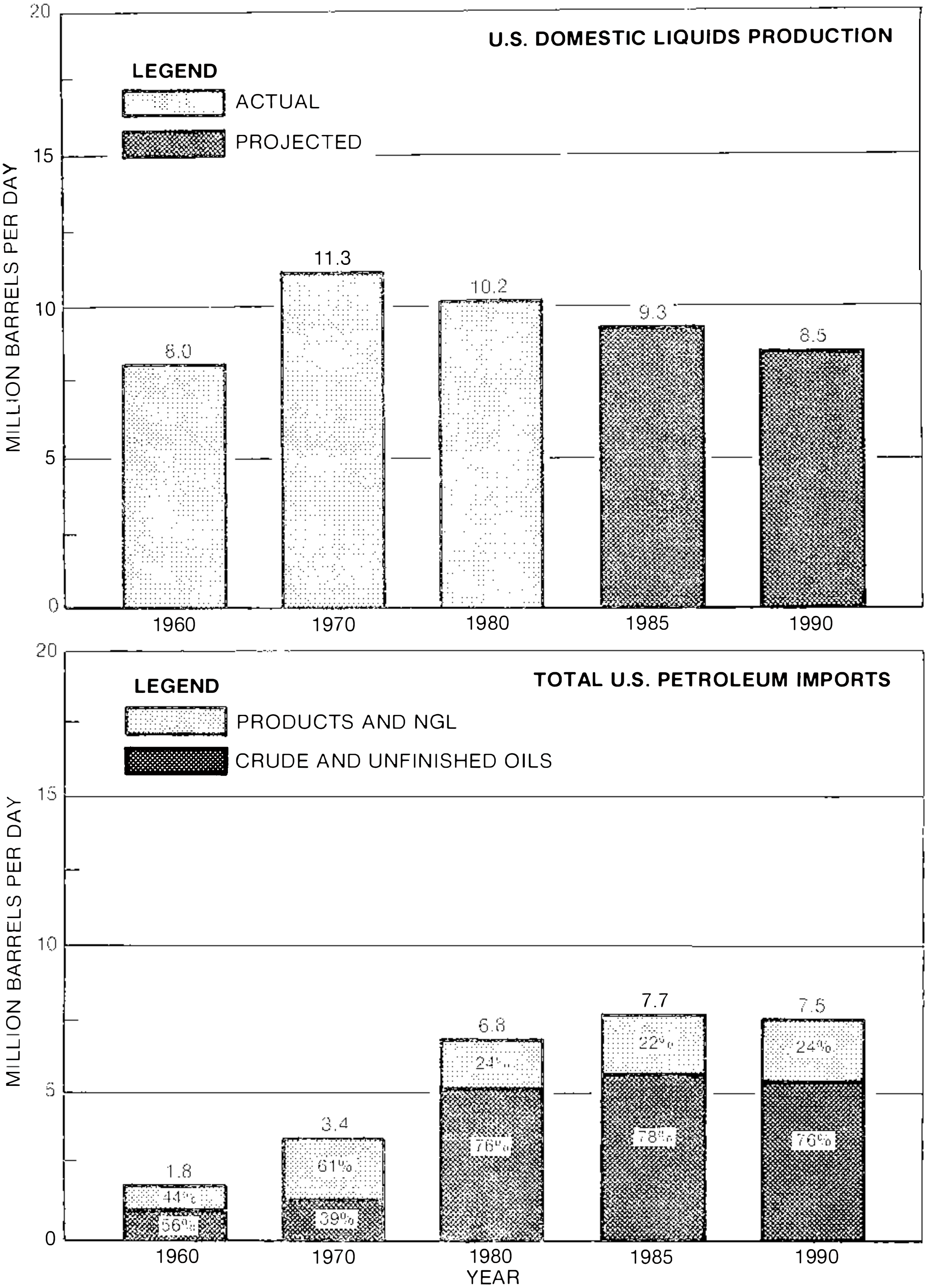


Figure 4. U.S. Liquids Production and Petroleum Imports—1960-1990.

NOTE: Actual data from Energy Information Administration, *1980 Annual Report to Congress*. Volume II. Projected data from National Petroleum Council, *Refinery Flexibility*. 1980. Percentages are share of total imports in year shown.

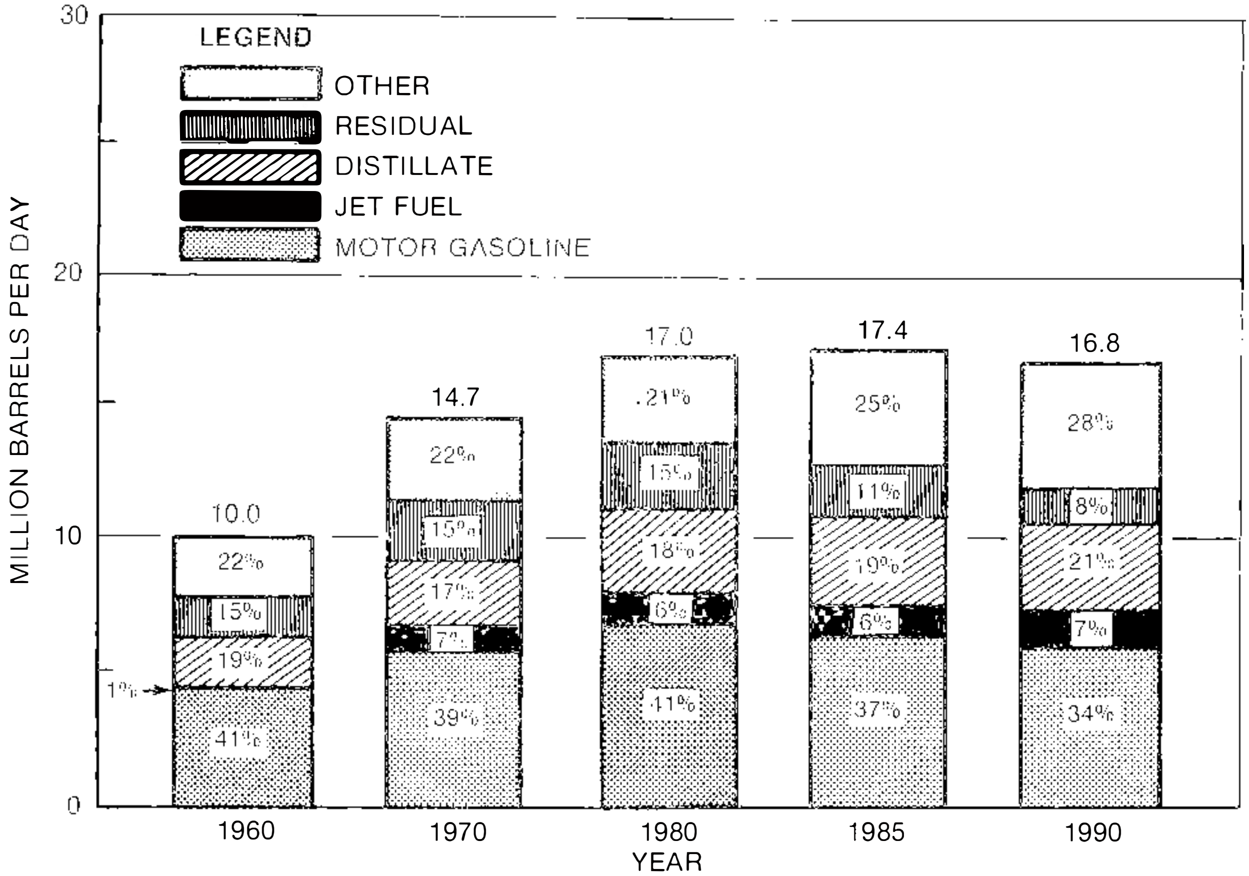


Figure 5. U.S. Domestic Petroleum Demand—1960-1990.

NOTE Actual data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Projected data from National Petroleum Council, *Refinery Flexibility*, 1980. Percentages are share of total demand in year shown.

TABLE 4

Total U.S. Demand for Products -- 1960-1990*
(Millions of Barrels Per Day)

	Actual			Projected	
	1960	1970	1980	1985	1990
Motor Gasoline	4.1	5.8	6.9	6.5	6.0
Jet Fuel	0.3	1.0	1.1	1.1	1.2
Distillate Fuel Oil	1.9	2.5	3.0	3.4	3.5
Residual Fuel Oil	1.5	2.2	2.5	2.0	1.4
Other	2.2	3.2	3.5	4.4	4.7
Total Domestic Demand for Products	10.0	14.7	17.0	17.4	16.8

*Actual data from Energy Information Administration, 1980 Annual Report to Congress, Volume II. Projected data from National Petroleum Council, Refinery Flexibility, 1980.

expected to remain fairly constant, although the economy as measured by the GNP is expected to grow. The demand will decrease from its peak of 18.8 MMB/D in 1978 to 16.8 MMB/D in 1990.

The most significant decline in the outlook for future U.S. product demand occurs in the demand for residual fuel oil, which is expected to decrease approximately 44 percent over the next decade. While the amount of high-sulfur residual fuel oil as a percentage of total residual fuel oil demand is expected to increase by 2 percent, the absolute volume is virtually half of the 1980 level.

Also, demand for middle distillates (kerosine and heating oil No. 1, kerosine-type jet fuel, and distillate fuels) is projected to remain essentially constant over the decade; motor gasoline demand is expected to decrease from a high of 7.4 MMB/D in 1978 to 6.0 MMB/D in 1990, of which only 0.5 MMB/D is anticipated to be leaded.

LEGISLATIVE AND REGULATORY CONSIDERATIONS

During the 1970's, government laws and regulations at all levels (federal, state, and local) placed an extraordinary number of constraints on the petroleum industry as well as on all the basic industries in the national economy. Those key laws that have a major impact on the petroleum industry are discussed below, as are the principal international marine conventions to protect the environment.

I. National

No other domestic policy challenges of recent times have been addressed by all levels of government as forcefully, quickly, and successfully as have the tasks of reducing the degradation of the U.S. environment and preserving its pristine areas. Since the NPC's 1971 report on this subject, the United States has entered into a long-term commitment to restore and protect the quality of the environment. Following the passage of the National Environmental Policy Act of 1970 (NEPA) at the start of the decade, some 43 other major environmental laws and amendments to those laws have been enacted, along with a number of others that are keyed to specific problem areas. Appendix C lists those laws by year of passage.

Beginning in the early 1970's, Congress increased the federal authority in pollution control and environmental protection. During this period, Congress also began to pass laws that established technology-based guidelines and technology-forcing provisions, in spite of the fact that the technologies were not fully developed. Industry was faced with the problem of equipping new and existing industrial plants with pollution control facilities whose reliability and efficiency had not yet been demonstrated.

In order to understand the breadth and complexity of the key laws passed during the 1970's, and to achieve an appreciation of

the interactions and multiplying effects, the following laws and their key aspects are discussed below.

- National Environmental Policy Act
- Clean Air Act
- Clean Water Act
- Safe Drinking Water Act
- Resource Conservation and Recovery Act
- Comprehensive Environmental Response, Compensation and Liability Act
- Endangered Species Act.

It is intended that this list be viewed without priorities in mind -- it is simply a listing of those statutes that represent major impacts on petroleum operations. The environmental considerations sections of this report address these and other laws and regulations specific to industry segments.

A number of key federal statutes and regulations impinge more directly on the petroleum industry operations in Alaska and they have been addressed in the NPC's 1981 report, U.S. Arctic Oil and Gas. The following are of particular interest to Alaska:

- Alaskan National Interest Lands Conservation Act
- National Petroleum Reserve-Alaska Leasing Act
- Department of the Interior's Fiscal 1981 Appropriations Act.

A. National Environmental Policy Act

The National Environmental Policy Act of 1970 set forth a national policy "to encourage harmony between man and his environment, to promote efforts to prevent or eliminate damage to the environment and promote the health and welfare of man, to encourage a better understanding of ecological systems and natural resources that are important to the nation, and to create a Council on Environmental Quality."

A key element of NEPA is its action-forcing provision -- the requirement that no major federal action affecting the environment may be taken by a federal agency until it has analyzed the environmental consequences of the proposed action and possible alternatives. Not all federal agency actions require an environmental impact statement (EIS). Some important actions, such as the granting of a Prevention of Significant Deterioration (PSD) permit, are exempt from the coverage of NEPA. Agencies also have the authority to make a finding after a brief environmental assessment that a proposed action will have no significant impact and prepare no

further analysis. In addition, some important petroleum industry permits such as onshore drilling permits normally require only an environmental assessment, even if there is no finding of significant impact. But where no exemption applies and there is some impact, an EIS must be prepared. Although some large projects have been approved without an EIS, it is nearly certain that any major energy project will involve at least one "major federal action," necessitating preparation of an EIS. Regardless of what triggers the EIS, the environmental analysis must cover the entire project and all of its impacts, not just the specific activity that may have forced the review.

The preparation of an EIS is a time-consuming process. The EIS must examine the environmental impact of the proposed action, adverse environmental effects that cannot be mitigated, alternatives to the proposed action, the relationship between short- and long-term benefits and costs, and irreversible commitments of resources associated with the proposed action. NEPA is essentially a procedural statute; where an EIS is necessary, it must be prepared in accord with a strict set of procedures. Early in the process, the agency must publish a notice of intent to prepare an EIS and invite public input to determine the scope of issues that will be addressed. After that, a draft EIS will be prepared and made publicly available. The agency must hold hearings on the proposal and the draft. Comments made on the draft by any party must be specifically addressed in the final EIS. Agency action on the proposed permit or other action cannot be made before publication of the final EIS and preparation of the public record of decision, indicating the factors that lead to its final choice. If an agency fails to meet the procedural requirements of NEPA, any party may go to federal courts and obtain an injunction preventing action until an adequate EIS has been prepared. NEPA legal suits rarely involve the merits of the proposed project, but rather turn on the question of whether a federal agency has met procedural requirements.

Preparation of an EIS, with its concomitant data collection and public hearings, may take between one and two years. This delay generally increases the project's costs. Although this activity has been incorporated into most of the planning processes, the delay can become critical at times and can add to the uncertainty of certain high-risk projects.

The methodology of EIS preparation often results in an examination of worst-case scenarios and other conjectural impacts, which may paint an unduly distorted picture of the likely hazards actually associated with the project. This can result in turning public opinion against the project. Utilization of proper risk techniques would provide a more balanced picture of the likely case.

B. Clean Air Act

The federal government first assumed responsibility for controlling air pollution under the Air Pollution Control Act of 1955. This Act was then amended by the Clean Air Act of 1963 and the Air Quality Act of 1967. Further amendments were added in 1970 and

1977. The 1970 amendments to the Clean Air Act formed the foundation for the nation's present approach to air quality management by establishing the requirement that National Ambient Air Quality Standards (NAAQS) (designed to protect public health and welfare) for pervasive pollutants be attained and maintained at all locations in the country. The 1970 amendments stipulated further protection of existing air quality by requiring the use of best available controls of pollutants at all new facilities. The PSD policy, codified into law in 1977, requires that geographic areas whose air quality is already better than NAAQS for a particular pollutant shall be protected against "significant deterioration" of that quality. Only a small increment, if any, of a NAAQS can then be added to the atmospheric burden of the pollutant under consideration in that area. The 1970 amendments also required that State Implementation Plans (SIPs) be developed to ensure compliance with the NAAQS and subsequently the PSD requirements. Visibility protection in large national parks, international parks, and wilderness areas was provided by the 1977 amendments.

In 1971, the Environmental Protection Agency (EPA) established NAAQS for six criteria pollutants: sulfur dioxide (SO_2), total suspended particulates (TSP), carbon monoxide (CO), nitrogen oxides (NO_x), oxidants, and non-methane hydrocarbons as an oxidant control method. Except for two changes, the initial standards have remained unaltered: deletion of the 24-hour and annual average secondary standards for SO_2; and redesignation of the oxidant standard to ozone [also made less stringent (0.08 to 0.12 parts per million)]. In 1978, a lead standard was adopted by EPA.

The 1977 amendments to the Clean Air Act required EPA to re-examine the NAAQS by December 31, 1980, and to re-examine each NAAQS every five years thereafter. This ongoing review of the NAAQS is an important activity relative to the nation's air pollution control program; any change in a standard could potentially affect other Clean Air Act requirements since all stationary source requirements have been designed to provide for compliance with the standards. In this way, the NAAQS are pivotal to the specific control strategies defined in the Clean Air Act.

EPA has responsibility for developing and promulgating the NAAQS, and primary (health-related) standards are to be based on current scientific knowledge concerning all identifiable health effects associated with a pollutant (which are summarized in a "criteria document"). Primary standards are established at a level intended to protect even the most sensitive members of the population and to provide, in addition, an "adequate margin of safety" below that level. Further, all but the annual standards can be exceeded only once per year. Therefore, the standards incorporate several factors of conservatism. Finally, the Clean Air Act specifically omitted costs from the factors EPA must consider in establishing the health-related standards. At present, there is considerable debate in the scientific and regulatory communities as to the form of the current standard-setting process and the basis for the specific numerical standards, including the margin of safety concept. These issues are presently under scrutiny by diverse

groups in the public and private sectors. Setting NAAQS is one of the key issues of the 1980's discussed in Chapter Eight.

As part of its review, EPA has reviewed the oxidant standard, altered the level, and changed the standards to incorporate specifically only ozone as the surrogate, as mentioned above; reviewed the CO standard; and indicated that it plans to eliminate the hydrocarbon standard. In addition, EPA is currently revising the criteria documents for TSP and SO_2. Changes to these standards may result from the ongoing reviews of health effects research. The first draft of the revised criteria document was reviewed by the Clean Air Scientific Advisory Committee (CASAC) of EPA's Science Advisory Board, at a public meeting in August 1980. Concern was expressed regarding deficiencies in the scientific bases for the TSP standard at that time. The TSP standard in its current form is considered by some CASAC members to be inadequate for the protection of public health and welfare, because the health effects of particles are suspected to be directly related to their size and chemical compositions. Neither of these properties is reflected in the current standards, which are based solely on mass concentration. Therefore, EPA is considering separate standards relating to sulfate particulates and inhalable particulate material. EPA has an extensive health effects research program in progress related to fine particulates, but major epidemiological components of the program will require several years for completion.

The 1970 amendments to the Clean Air Act specified that all states were to attain the primary NAAQS by May 31, 1975 (in limited cases, an extension to July 1977 was possible); secondary standards were to be attained within a "reasonable period of time," generally within three years of primary NAAQS attainment. (The 1977 amendments to the Clean Air Act subsequently required attainment of the primary standards by 1982, with possible extension to 1987 for ozone and CO). However, due to problems in achieving the NAAQS in many areas of the country, EPA developed an Emissions Offset Policy in December 1976, which was subsequently incorporated in Part D (Nonattainment) of the Clean Air Act as amended in 1977. This policy states that major new and expanded sources must offset any projected emissions increases with even greater corresponding reductions in emissions in the area of proposed source location.

As the United States seeks to develop domestic oil and gas supplies in the next decade, various facilities subject to air quality regulations will be developed. These developments include modifications to existing facilities and construction of new capacity in "grassroots" or greenfield areas (generally lacking supporting infrastructure) and at more developed sites. The specific procedures or pre-construction reviews of major oil and gas facilities are dependent upon the attainment status of the NAAQS for each pollutant to be emitted in significant quantity by the facility. Where the NAAQS are not being attained, the facility owner/operator must comply with the pre-construction review procedures governing nonattainment; where the NAAQS are being attained, the facility owner/operator must comply with the pre-construction review procedures governing PSD areas. Occasionally, a single facility will be

subject to both sets of pre-construction review procedures (e.g., where an area is designated as nonattainment for one or more pollutants and attainment for other pollutants).

The total permit preparation and processing time for major new and modified facilities is frequently 22 to 48 months. Of that time, EPA averages only 8 1/2 months for its review and approval of the permit, including public hearings, due in part to EPA's implementation of a high-priority system for energy-related projects. Such detailed pre-construction review often results in delay and uncertainty, which can increase the risks of capital investment and of the ultimate viability of projects. Recent studies have indicated that the pre-construction review process could be simplified, thereby allowing significant cost and time savings in improving the efficiency and certainty of industrial planning and development.[1] In the case of the oil and gas industries, improvement of the pre-construction review process is critical as efforts to develop and produce energy intensify in this decade.

1. Prevention of Significant Deterioration

The national goal to preserve air quality in less polluted regions (i.e., prevent significant deterioration of air quality) was explicitly codified into Part C of the Clean Air Act in August 1977. The stated purposes of the PSD policy are to preserve the special air quality characteristics of national parks and other identified areas, and to allow moderate growth of well-controlled facilities at suitable locations in other clean air areas. To meet this goal, the PSD rules establish emission control and siting requirements on all new and expanded major emitting facilities in clean air areas. These rules can limit the size of individual plants as well as the total number of sites potentially suitable for industrial development. Three classes of clean air areas have been established and maximum increases of SO_2 and TSP concentrations have been specified for each area. These incremental values (expressed in micrograms per cubic meter) are small percentages of the related NAAQS for each pollutant. Control of air pollution through the PSD policy, therefore, by definition goes well beyond the control levels needed to protect public health.

PSD in the past has created substantial technical and administrative uncertainties and delays in major plant construction in the country. A serious case is its potential impact on energy resource development in the West, if the allowable increments are fully utilized.

The PSD provisions of the 1977 amendments introduced:

- Formal designation of attainment (PSD) areas.
- More stringent PSD increments for SO_2 and TSP (than EPA's 1974 regulations) in Class II and III areas.
- Mandatory designation of Class I areas for the following areas in existence as of August 7, 1977: international

parks, national wilderness areas, and memorial parks larger than 5,000 acres; and national parks larger than 6,000 acres. There are 158 Class I areas nationwide.

- Expansion of the number of source categories subject to PSD pre-construction review from 19 to 28. Petroleum refineries and fuel conversion plants are two of the 28 specified source categories.

- A "two-tier" system, which was established for PSD pre-construction review. Major new and modified stationary sources within the 28 specified categories are subject to PSD review if they have the potential to emit 100 tons or more per year of any pollutant regulated under the Clean Air Act. The emission threshhold for stationary sources other than the 28 specified is 250 tons per year.

- Increased application of Best Available Control Technology (BACT) to all pollutants regulated under the Act. In addition, BACT is to be determined on a case-by-case basis and must be at least as stringent as the applicable New Source Performance Standards (NSPS).

- More sophisticated modeling and monitoring requirements to demonstrate compliance with the increments (and ambient standards).

- Specific air quality and meteorological monitoring requirements were added to the PSD review process.

- Requirements for additional analysis of impacts associated with a proposed new source or modification of air quality related values were added.

- Additional PSD provisions, which were to be developed by August 7, 1979, for the other criteria pollutants. PSD rules for lead were to be promulgated by October 5, 1980.

On June 19, 1978, EPA promulgated regulations, issued in two parts, to implement the PSD program established by the 1977 amendments. The 1978 PSD regulations were challenged by both industry and environmental groups in Alabama Power vs. Costle, heard by the U.S. Court of Appeals for the District of Columbia Circuit. On June 18, 1979, the federal court released a preliminary decision and entertained petitions for reconsideration of some issues. Meanwhile, to expedite the regulatory process governing pre-construction review, EPA responded to the court's initial decisions with proposed major amendments to the PSD regulations on September 5, 1979. On December 14, 1979, the court issued its final opinion, but stayed the effect of the decision pending EPA's program for final implementation of its mandate. As a result of the court's opinion, the final PSD regulations were ultimately promulgated by EPA on August 7, 1980.[2]

2. Nonattainment

Part D of the Clean Air Act, as amended in 1977, establishes specific provisions to permit limited industrial growth in areas of the country designated as nonattainment, in order to foster simultaneous improvement in air quality. A nonattainment area is a bounded region in which air quality levels do not comply with the NAAQS for one or more pollutants based on valid monitoring data and/or air quality modeling results. On March 3, 1978, EPA published its first list delineating the attainment status of areas throughout the country. This list is updated (usually at the state's initiative), as the air quality in each area improves, degrades, or the designation is changed by new data.

Under the Clean Air Act, states were required to revise their SIPs by January 1, 1979 (with EPA review to be completed by July 1, 1979), to include detailed strategies for bringing nonattainment areas into compliance by December 31, 1982 (the attainment date was extended to 1987 in limited cases). The Act further authorizes EPA to impose no-growth sanctions in areas of states or territories for which there is no approved SIP. As of May 1981, a total of 31 states and one territory had no approved SIP for at least one pollutant. To date, EPA has imposed moratoriums on construction of major new or modified facilities in portions of over 30 states and several major source permits have been delayed.

Major new and modified sources proposed for location in nonattainment areas or having an impact on nearby nonattainment areas are subject to the requirements listed below:

- Lowest Achievable Emission Rate
- SIP compliance or an approved plan for compliance of all sources owned by the applicant within the state
- Offsets greater than one to one
- Positive net air quality benefit.

The complexity of these requirements adds to the time, cost, and uncertainty of obtaining the necessary permits. The availability of satisfactory offsets might become critical in facilities and areas that are already heavily controlled in attempts to meet NAAQS. Collectively, these may cause viable energy projects to be cancelled while still in the planning stage.

3. Future Amendments to the Clean Air Act

Modification of the PSD and nonattainment provisions of the Clean Air Act may result from Congressional review pursuant to reauthorization of the Act. Many industry groups, environmental organizations, and local, state, and federal government entities have prepared proposals for Congressional consideration. While there is great diversity in these proposals, there is wide support for simplifying the permit review process.

The NPC believes that modifications to the Clean Air Act could alleviate some of the problems inherent in the existing PSD and nonattainment permit review requirements and could improve the certainty and efficiency of the planning and development processes for new and expanded sources in the petroleum industry. The following issues should be considered in any future amendments to the Clean Air Act:

- Setting of NAAQS based on valid scientific studies subject to peer review
- PSD increments, including disposition of Class II and III increments
- Emissions offset requirements in nonattainment areas
- Pre-construction permit process
- Scope of visibility protection requirements
- Use of cost-effectiveness and/or cost-benefit analyses as the basis for specific legislative provisions and implementing regulations
- Federal sanctions in nonattainment areas.

C. Clean Water Act

The 1972 amendment to the Federal Water Pollution Control Act expanded an existing federal role in water pollution control. It expanded water quality standard programs initiated in 1965 and extended the national program to all navigable waters in the United States. It created a system of uniform national technology-based effluent limitations, or more stringent limitations if required, to meet water quality standards. It instituted a national permit system for all point source discharges, and specific deadlines were established for achieving those effluent limitations based on designated control technologies. Two general goals were proclaimed: to achieve, wherever possible, by July 1, 1983, water that is clean enough for swimming and other recreational uses, and clean enough for the protection and propagation of fish, shellfish, and wildlife; and by 1985, to have no discharge of pollutants into the nation's waters.

The Clean Water Act Amendments of 1977 made major mid-course corrections to the 1972 law and incorporated many of the provisions of a previous court settlement on toxics control, adding new emphasis to the control of the discharge of toxic pollutants. It divided pollutants into three classes -- conventional, nonconventional, and toxic -- and different discharge requirements were established for each class. Additional pretreatment requirements were established for discharges to municipal sewage treatment systems and EPA was authorized to control the runoff of toxic and hazardous materials from industrial sites through Best Management Practices.

The 1978 amendments to the Clean Water Act specifically revised provisions dealing with Section 311 discharges of oil and hazardous substances. These issues included the determination of harmful quantities, penalties, and exclusion for hazardous substance discharges regulated under National Pollutant Discharge Elimination System (NPDES) permits.

The four principal sections of the Act that have direct impact on the petroleum industry are: Section 402, National Pollutant Discharge Elimination System; Section 404, permits for dredge or fill material; Section 311, oil and hazardous substances liability; and Section 401, governing state certification of federal permits for discharges originating in state waters.

1. NPDES Permits

The Clean Water Act prohibits the discharge of any pollutants, except as authorized by an NPDES (or other) permit. Each NPDES permit required compliance with effluent limitations by July 1, 1977, reflecting the Best Practicable Control Technology Currently Available. By July 1, 1984, NPDES permit effluent limitations further require application of the Best Available Technology Economically Achievable (BAT) for toxic and nonconventional pollutants and the Best Conventional Pollutant Control Technology for conventional pollutants. The Clean Water Act provides for waivers from BAT for nonconventional pollutants in some cases. New sources are required to comply with NSPS, which reflect the greatest degree of effluent reduction achievable through application of Best Available Demonstrated Control Technology, processes, operating methods, and other alternatives including, where practicable, a standard permitting no discharge of pollutants.

2. U.S. Army Corps of Engineers Permits

Section 404 permits are issued by the U.S. Army Corps of Engineers for the discharge of dredge or fill material into the navigable waters. Guidelines for permit issuance are developed by EPA based upon criteria comparable to the criteria applicable to the territorial seas and oceans. EPA, a state, or an adjacent state may add stipulations to the Section 404 permit or prohibit its issuance. EPA may withdraw the permit for a disposal site for dredge or fill material whenever it determines, after a public hearing, that the discharges will have an unacceptable adverse effect on the receiving waters. To understand the real significance of expanded review authority of the Corps of Engineers for such permits, one must look at the related legislation that impacts on the permitting decisions of the Corps.

- Section 401 of the Clean Water Act requires certification from the state in which the discharge originates that the discharge will comply with the applicable effluent limitation and water quality standards.

- Section 307 of the Coastal Zone Management Act requires an applicant to furnish a certification that the proposed

activity will comply with the state's Coastal Zone Management program. No permit will be issued until the state has concurred with the applicant's certification.

- Section 302 of the Marine Protection, Research and Sanctuaries Act authorizes the designation of marine sanctuaries. Activities in the sanctuaries authorized by the Corps of Engineers are valid only if the Secretary of Commerce certifies that the activities are consistent with the purposes of the Act and can be carried out within the regulations for the specific sanctuaries.

- NEPA may require an EIS when several Corps of Engineers permits are issued in one specific area. An EIS may also be required by an application for a permit that results in a major federal action in the opinion of the Corps.

- The Fish and Wildlife Act requires that before the Corps of Engineers issues any permit that proposes to control or modify any body of water, the Corps must first consult the U.S. Fish and Wildlife Service, the National Marine Fishery Service, as appropriate, and the head of the appropriate state agency exercising administration over the wildlife resources of the affected state.

- The National Historical Preservation Act authorizes that its advisory council review activities licensed by the Corps that will have an effect upon properties listed in the National Register of Historical Places or eligible for such listing.

- The Preservation of Historical and Archaeological Data Act provides that the Corps of Engineers may delay granting a permit if the permitted activity would alter any terrain such that significant historical or archaeological data are threatened, until the Secretary of the Interior takes action necessary to recover and preserve the data.

- The Endangered Species Act provides that the Corps of Engineers must utilize its authorities by carrying out programs for the conservation of endangered or threatened species and by taking such action as is necessary to ensure that any action authorized by the Corps will not jeopardize the continued existence of such species or result in the destruction or adverse modification of the habitat of such species.

- The Marine Mammal Protection Act of 1972 imposes a perpetual moratorium on harassment of marine mammals and has the potential for preventing the issuance of a Corps permit.

- The Wild and Scenic Rivers Act provides that the Corps of Engineers shall not assist by permit or otherwise in the construction of any water resources project that would have a direct and adverse effect on the values for which a river was designated a wild and scenic river.

- In addition to all of these, where an application affects wetlands, the District Engineer of the Corps may undertake reviews of particular wetland areas in consultation with the appropriate regional director of the Fish and Wildlife Service, the National Marine Fishery Service, the National Oceanic and Atmospheric Administration, the Regional Administrator of EPA, local representatives of the Soil Conservation Service of the Department of Agriculture, and the head of the appropriate state agency to assess the cumulative effect of activities in such areas.

3. Oil and Hazardous Substance Spills

The Clean Water Act prohibits the discharge of oil or hazardous substances, in quantities that may be harmful, into or upon the navigable waters of the United States. A new National Contingency Plan is required for the removal of oil and hazardous substances and is now expected to be published in 1982. This plan will assign duties and responsibilities among federal departments and agencies in coordination with state and local agencies. Regulations are specified to cover methods of procedures for prevention of spills as well as of removal of any accidental discharges. Spillage of any designated material that may be harmful must be immediately reported to the National Response Center.

4. State Certification

The Clean Water Act also requires that NPDES permits contain conditions that ensure compliance with applicable state water quality standards or limitations. Under another section of the Act, EPA may not issue an NPDES permit until the state in which the discharge will originate grants or waives certification to ensure compliance with appropriate requirements of the Clean Water Act and state law. These stipulations frequently result in conflicts between the federal agency and the state agency with a resultant delay in the issuance of the final NPDES permit and the approval to construct a new facility or modify an existing facility with the necessary pollution control.

D. Safe Drinking Water Act

The Safe Drinking Water Act directs the establishment of two major regulatory programs. One program relates to public water systems and requires that EPA establish national primary and secondary drinking water standards for public water systems. This statute directs the primary enforcement responsibility to the states to ensure that public water systems comply with the national standards. The other program, which has the larger impact on the oil and gas industries, relates to underground sources of drinking water, and it requires that EPA publish regulations for state underground injection control (UIC) programs. The UIC programs regulate the re-injection of produced waters from exploration and production operations, underground cavern storage of petroleum products, and underground injection of hazardous wastes. These

regulations must establish minimum requirements for effective programs to prevent underground injection that endangers drinking water sources. These regulations are in addition to the requirements set by state regulatory agencies. Oil and gas producing states have developed and implemented very effective UIC regulations.

E. Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act of 1976 (RCRA) provides a comprehensive program for the regulation of wastes. It greatly expands the role of the federal government in the field of waste disposal, with particular emphasis on the regulation of hazardous waste and resource recovery. The program is to be achieved through implementation of several programs: the establishment of a hazardous waste control program; a solid waste management program in each state, together with a prohibition on the practice of open dumping; and the encouragement, through federal aid, of state and regional waste management planning.

The statute allows states to apply to EPA for authorization to administer the hazardous waste program. EPA has issued regulations and has established minimum requirements for state hazardous waste programs in order to receive EPA approval.

Of particular interest to the petroleum industry is the regulation, from generation to final disposal, of hazardous wastes. EPA has promulgated regulations defining hazardous wastes, setting requirements for generators and transporters, and setting interim status standards for existing facilities that treat, store, and dispose of hazardous wastes. Final standards for hazardous waste management facilities are still being developed. The petroleum industry is affected primarily by the broad classification of hazardous wastes identified by EPA, which fails to distinguish between wastes that pose a lesser degree of hazard and such extremely hazardous materials as Kepone or dioxin. This classification system will result in secure disposal sites being used for waste with a low degree of hazard, thereby increasing the shortfall of needed capacity to dispose of truly hazardous waste.

An important question, primarily because of the potential financial impact on the industry, is whether EPA will determine that wastes associated with the drilling and producing sector of the petroleum industry should be covered by RCRA regulations. At the present time, wastes associated with petroleum and natural gas drilling and production are excluded from the definition of hazardous wastes. EPA does not anticipate completing the necessary research work in this area and the possible regulations until at least 1985. Compliance with the regulations proposed in December 1978 could have resulted in increased capital costs to the oil and gas drilling industry of $31 billion (in mid-1978 dollars) as well as increased annual direct operating and maintenance costs of $3.3 billion.[3]

In light of the concern that is expressed by the public and the difficulty in satisfying the EPA criteria for hazardous waste

disposal sites, a great deal of difficulty is envisioned in the siting of hazardous waste disposal facilities and the subsequent operation of those facilities. The potential lack of facilities, especially in proximity to those facilities that generate most of the hazardous wastes, can lead only to very high transportation and administration costs.

One approach to the solution of the potential lack of disposal facilities is legislation to establish and control such facilities in a manner similar to that of public trusts. Private or publicly owned hazardous waste disposal corporations would be encouraged by appropriate federal and state legislation to establish and operate disposal sites on properly designated lands. Proper schedules of charges for disposal, together with a regulated profit margin would be authorized. Proper compliance with construction, operation, maintenance, recordkeeping, and closure standards would be assured under terms of the site contract as well as regulatory provisions in the enabling legislation. After final closure, the land would revert to the federal and/or state government for stabilization and containment of the waste in perpetuity. Such an organization could assure the nation that hazardous wastes would be handled safely and in compliance with all applicable control requirements.

F. The Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, or "Superfund," establishes a federal fund to finance government action to prevent threatened releases of hazardous substances or to remedy the effects of past releases of such substances. It provides for strict liability on the part of owners and operators of vessels and waste disposal sites for the release of hazardous materials into the environment. Through imposition of an excise tax on crude oil, petroleum products, and 42 basic industrial chemicals, a $1.6 billion fund will be established to enable the government to pay cleanup costs resulting from releases of hazardous substances into the environment when the culpable party is unknown or unable to pay The reporting requirements under the Act are expected to reveal the existence of hazardous waste disposal sites that are not regulated, i.e., not active under RCRA. Serious liability consequences may result to companies that are subsequently found to have used sites that are creating a danger to human health or the environment.

The ultimate effects of Superfund are somewhat less predictable for the petroleum industry than for some other industries at this point. The "deep pocket" approach, under which enforcement is pressed against the party most likely to be able to pay, regardless of the extent of culpability, could place an extreme liability on financially solvent generators of hazardous wastes. Such generators are assumed to bear a liability for correcting disposal site problems even though their only connection with the disposal operation is their contribution of wastes for disposal. The total impact of Superfund on the petroleum industry cannot be determined until the regulatory program is completed.

G. The Endangered Species Act

The Endangered Species Act mandates affirmative action to preserve endangered and threatened species. It declares that there is a public responsibility to prevent the extinction of species of fish, wildlife, or plants that would occur as a consequence of economic growth or development; and it encourages the states, through federal financial incentives, to develop and maintain conservation programs that work to meet this goal. It further provides that an entire ecosystem of a threatened species may be conserved, and declares that it is the policy of Congress that all federal departments and agencies shall seek to conserve endangered species and use their authorities in furtherance of the Act.

This law presents barriers to petroleum industry development because it is written in general language, providing the Executive Branch regulators with significant new powers but little or no operational guidance. The impact of the program has grown significantly in recent years. The entire ecosystem of an endangered species may encompass a vast amount of acreage or ocean that would be placed off limits to natural resource development. The list of endangered domestic flora and fauna contains approximately 300 species.

II. International Marine

Nations have a great interest in promoting a satisfactory quality of international waters both of the high seas and of international basin drainage systems. Pollution of the high seas endangers the quality and resources of the territorial waters of coastal nations and, of course, the shores as well.

A. Intergovernmental Maritime Consultative Organization

To serve as the institutional mechanism for establishing worldwide vessel standards, the Intergovernmental Maritime Consultative Organization (IMCO) was founded in 1959 under the auspices of the United Nations. Since its inception, IMCO has been primarily a maritime-nation agency dealing with technical maritime problems. The costs of IMCO administration are divided among the maritime nations according to the tonnage of vessels flying each nation's flag. Non-maritime nations have a standing invitation to attend IMCO meetings, but few have done so and their voting power has not been substantial.

The following international conventions developed by or under the jurisdiction of IMCO relate to vessel safety and pollution prevention:

- International Convention for Safety of Life at Sea (SOLAS), 1960 and 1974 (general life-saving requirements for vessels).

- International Convention on Load Lines, 1966 (established load limits).

- International Regulation for Preventing Collisions at Sea, 1971 (voluntary rules of the road).

- International Convention for the Prevention of Pollution of the Sea by Oil, 1954 (operation discharge standards and prohibited discharge zones), amended 1962, 1969, and 1971. All amendments except 1971 are in force.

- International Convention Relating to Intervention on the High Seas in Cases of Oil Pollution, 1971 (rights of a coastal nation to protect itself from a disabled vessel carrying oil).

- International Convention on Civil Liability for Oil Pollution Damage, 1969 (sets strict liability with limits for shipowners in cases of oil pollution).

- Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage, 1971 (creates an international fund to cover oil pollution damages beyond the liability of the shipowner).

- International Convention for the Prevention of Pollution From Ships, 1973 -- referred to as MARPOL 1973 (new discharge and construction standard treaty for all polluting substances designed to substitute for the 1954 Convention -- not yet enforced).

- Tanker Safety and Pollution Prevention Convention of February 1978 -- referred to as MARPOL 1978 (requires segregated ballast tanks, dedicated clean ballast tanks, or crude oil washing equipment on existing and new vessels -- not yet enforced).

- Standards of Training, Certification and Watchkeeping for Seafarers, 1978 (national licensing programs, and improvements in training, qualification, and certification for tanker personnel -- not yet enforced).

The status of IMCO-related international conventions is shown in Table 5.

International efforts to strictly control vessel-source pollution were actually initiated at the behest of the United States. A conference on the subject convened in 1926 in Washington, D.C., but a U.S. proposal for a total prohibition of oil discharges from ships was defeated two to one. It was not until 1954 that a convention was finally concluded -- but without a discharge ban. International discharges were merely limited and enforcement was to be carried out by the flag-nation, using penalties it determined appropriate. Nations other than the flag-nation could inspect the vessel's oil record book (mandated by the 1954 Convention) only when it called at their ports and, if discrepancies were discovered, they would have to request the flag-nation to take enforcement action.

TABLE 5

Status of IMCO-Related International Conventions

Convention	Date of U.S. Ratification	Date In Force Internationally
Safety of Life at Sea (SOLAS), 1960		1965
Amendments:		
1966 (Fire safety)	04-07-67	
1967 (Fire safety/radio)	06-10-68	
1968 (Navigation/equipment)	11-22-72	
1969 (Equipment, surveys, and radio)	11-22-72	
1971 (Radios and routing)	11-16-73	
1973 (Editorial)	02-03-76	
1973 (Grain)	02-03-76	
Safety of Life at Sea (SOLAS), 1974	09-07-78	05-25-80
1978 Protocol (TSPP)	08-12-80	05-01-81
Collision Regulations, 1972	11-23-76	1977
Oil Pollution, 1954		1958
Amendments:		
1962 (Rewrite)	09-21-66	1967
1969 (Eliminates prohibited zones, allows limited discharge)	10-17-73	1978
1971 (Tanker tank size)		
1971 (Great Barrier Reef)		
International Pollution from Ships (MARPOL), 1973		
1978 Protocol (includes modified text of 1973 convention)	08-12-80	
Load Line, 1966	11-17-66	1968
1975 Amendments	08-12-80	
Tonnage Measurement, 1969		07-18-82
Intervention, 1969 (High seas, oil pollution casualties)	02-21-74	1975
Civil Liability, 1969		06-19-75
Compensation Fund, 1973		10-16-78
Safe Containers (Geneva, 1972)	01-03-78	09-06-77
Search and Rescue Convention, 1979	08-12-80	
Intervention, 1973 (High seas, other than oil)	09-07-78	
Ocean Dumping (London, 1972) non-IMCO	04-24-74	1975
Standards of Training, Certification, and Watchkeeping, 1978		

The discharge standards and prohibited zones were made more stringent in 1962. The 1969 amendments did away with zones altogether and limited the rate of discharge of oil even further. But the discharge standards adopted would still permit a 300,000 deadweight ton (DWT) tanker to discharge a maximum of 20 tons during the course of any one ballast voyage at a rate not to exceed 80 liters per mile.

The 1971 amendments to the 1954 Convention are more significant. For the first time, construction standards were developed to prevent or minimize oil outflow in the event of an accident. These requirements restrict cargo tank size as a means of limiting maximum oil outflow resulting from a tanker collision or grounding. The 1954 Convention and amendments were subsequently superseded by MARPOL 1973 and MARPOL 1978.

MARPOL 1973 was developed in London in November 1973, and represented the most comprehensive treaty on the subject to that time. Included were measures to control more pollutants than ever before and emphasis was put on prevention rather than cleanup and other post-accident measures. Briefly, the new treaty included the following salient features:

- Regulation of ship discharges of oil, various liquid substances, and harmful package goods
- Control, for the first time, of tankers carrying refined products
- Requirements for segregated ballast for all tankers over 70,000 DWT contracted for after December 31, 1975 (but does not require double bottoms)
- Prohibition of all oil discharges within 50 miles of land (as did the 1969 amendment)
- Mandate for all tankers to operate with the load-on-top system, if capable
- Reduction of maximum permissible discharge for new tankers from 1/15,000 to 1/30,000 of cargo capacity (Note: no total discharge prohibition)
- Regulation of the carriage of 353 noxious liquid substances with requirements ranging from reception facilities to dilution prior to discharge
- Control of harmful package goods in terms of packaging, labeling, stowage, and quantity limitations
- Prohibition of discharge of sewage within four miles of land unless the ship has an approved treatment plant in operation, and from 4 to 12 miles unless the sewage is macerated and disinfected.[4]

In the area of enforcement, the international legal status quo was modified to some degree. The flag-nation must punish ship owners for all violations. A coastal nation has the right (as well as the duty) to punish the owner of a foreign-flag vessel for violations occurring in its waters or to refer the violation to the flag-nation for prosecution. Nations that ratify the treaty must apply its terms to all vessels, including those flying flags of nations that do not sign the treaty, in order to prevent vessels of nonsignatory nations from gaining competitive advantage. To settle any disputes, compulsory arbitration is a treaty requirement.

On the question of standard-setting authority, a provision was defeated that would have made the treaty provisions exclusive on subjects it addressed. Consequently, there are no treaty restrictions on the right of coastal nations to set more stringent requirements within their jurisdictional waters.

The MARPOL 1973 Convention must be ratified by at least 15 nations that, among them, represent at least 50 percent of the total tonnage in the world fleet. Since previous conventions required ratification by 32 nations, this represents a significant easing of the ratification process.

In mid-December 1976, the Argo Merchant ran aground and broke up near Nantucket, Massachusetts. In a little over three months there were 14 more tanker-related incidents off U.S. coasts. Of these, almost two-thirds were serious. Following these accidents, the President warned the world maritime community that the United States intended to ensure that the events of the winter of 1976-1977 would not re-occur. The Administration suggested that the United States would take unilateral action if necessary, but that it would prefer to join the international shipping community in improving tanker regulations and existing pollution prevention measures. In response to the President's initiatives, the Tanker Safety and Pollution Prevention Conference was convened in February 1978. The outcome of this IMCO conference was the adoption of amendments to SOLAS 1974 and MARPOL 1973. Because procedural constraints do not permit amendments to conventions that are not in force and neither SOLAS 1974 nor MARPOL 1973 had been ratified by the requisite number of states at the date of the convention, the conference results became "protocols" to these two conventions. The new requirements are as follows:

- SOLAS Protocol 1978
  - Improved inspection and certification procedures for all ships.
  - Inert gas systems for all new tankers of 20,000 DWT and over and existing tankers of 40,000 DWT or more.
  - Second radar on all ships over 10,000 gross registered tons (GRT). IMCO was obligated to prepare a performance specification for collision avoidance aids.

- Improved emergency steering gear requiring two independent steering control systems for all tankers 10,000 GRT or more.

- MARPOL Protocol 1978

  - Protective location of segregated ballast tanks in the side and bottom shell areas for new tankers

  - Clean ballast tanks as an alternative to segregated ballast on product tankers by using dedicated cargo tanks only for clean ballast water

  - Crude oil washing for tankers of 20,000 DWT and over and as an alternative to segregated ballast for existing crude oil tankers of 40,000 DWT or more.

MARPOL 1973 and its 1978 Protocol are not yet in force; however, SOLAS 1974 has been in force since May 1980 and its 1978 Protocol came into force on May 1, 1981.

Recognizing the importance of the human element in mitigating pollution incidents on the seas, IMCO called a conference that resulted in an International Convention on Standards of Training, Certification and Watchkeeping for Seafarers, 1978. This conference was the first ever called to establish international standards for ships' officers and crews. Specifically, the Convention provides for the submission of national licensing programs and the exchange of data among parties, and it provides for the training, qualification, and certification of tanker personnel.

COSTS OF ENVIRONMENTAL CONTROLS TO THE PETROLEUM INDUSTRY

I. The Past

The Secretary of Energy requested of the NPC information on the impact of environmental controls on the cost of petroleum products and natural gas. The American Petroleum Institute's (API) Annual Expenditure Survey describes and documents the cost to U.S. petroleum companies, representing 70 percent of U.S. refining capacity.[5] These costs are reported as spent and have not been extrapolated to include the nonreporting companies. The annual report shows the specific costs for the current 10-year period with a variety of parameters: total expenditures; capital expenditures; administrative, operating, and maintenance expenditures; and research and development expenditures for each year. The details of those expenditures are broadened to identify the costs for air, water, and land and other, as well as for the industry operating segments: exploration and production, transportation, marketing, and refining. These costs include only firmly identified expenditures and do not include costs of delays or lost opportunities resulting from environmental regulations.

Specific details of the latest survey are provided in Tables 6, 7, 8, 9, and 10. Figures 6, 7, and 8 show some very interesting trends in expenditures, especially the dramatic increase in operating expenditures when compared with capital expenditures. This increase is due in part to the large increase in the cost of energy to operate the control equipment and the process units to make environmentally acceptable products, as well as the increased effort to operate and maintain the new pollution control devices. By 1979, the total expenditures for the 10-year period for capital and operating expenses were essentially the same, approximately \$8.5 billion each. By 1980, the total 10-year operating expenditures exceeded the capital expenditures by almost \$1.1 billion and that trend is predicted to continue.

II. The Future

During the 1970's, Battelle Columbus Laboratories analyzed the cost of environmental regulations to the U.S. domestic petroleum industry.[6] The 1980 report conducted during the 1978-1979 period not only included the cost of controlling pollution in production, refining, transportation, and marketing, but also added the cost of providing products that met the specifications set by environmental regulations.

The Battelle report estimates costs for the entire petroleum industry and presents its results in terms of constant 1979 dollars. These costs are different from the API-reported costs.

The analysis developed both capital and operating costs and from these developed an annualized cost using a 12.5 percent return after taxes. Two cost scenarios were developed -- an anticipated case, which assumes moderate regulatory severity, and a restrictive case, which assumes a severe one. This report will use the anticipated case where regulations are in place or nearly so and the restrictive scenario only in the case of those regulations resulting from RCRA.

The cumulative capital investment by 1990 is \$57 billion (constant 1979 dollars, excluding RCRA requirements) in the anticipated case. The annual capital cost for 1990 is \$2 billion; of particular interest is the fact that the increased energy required in 1990 for the facilities represented by these expenditures is equivalent to approximately 450,000 barrels of oil per day.

The most costly potential regulations are those related to RCRA, which amount to an annualized cost of \$44 billion in 1990 using a strict interpretation of regulations announced at the time of the study. Because of uncertainties in regulations to be proposed and legislation being considered at the time, it was impossible then and now to properly evaluate the impact. It is now anticipated that EPA's approach will be moderated to a large degree so that this is an exaggerated case in the short term.

TABLE 6

Summary of Environmental Expenditures of the Petroleum Industry -- 1971-1980
(Millions of Dollars)

	Year 1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	Total 1971-1980
						Total Expenditures (Table 7)					
	$571	$550	$737	$932	$1,039	$1,216	$1,188	$1,349	$1,616	$2,184	$11,382
Water	415	379	402	530	629	822	950	884	1,001	1,299	7,311
Land and Other	101	91	100	150	456	336	383	194	203	357	2,371
Total	$1,087	$1,020	$1,239	$1,612	$2,124	$2,374	$2,521	$2,427	$2,820	$3,840	$21,064
						Capital Expenditures (Table 8)					
Air	$391	$305	$436	$527	$601	$536	$339	$429	$561	$728	$4,853
Water	224	184	194	271	356	411	434	340	394	527	3,335
Land and Other	57	51	52	97	396	269	184	89	92	183	1,470
Total	$672	$540	$682	$895	$1,353	$1,216	$957	$858	$1,047	$1,438	$9,658
						Administrative, Operating, and Maintenance Expenditures (Table 9)					
Air	$143	$198	$251	$352	$389	$635	$792	$864	$997	$1,392	$6,013
Water	185	187	201	249	262	401	502	532	594	754	3,867
Land and Other	41	37	43	50	55	63	197	101	106	165	858
Total	$369	$422	$495	$651	$706	$1,099	$1,491	$1,497	$1,697	$2,311	$10,738
						Research and Development Expenditures (Table 10)					
Air	$37	$47	$50	$53	$49	$45	$57	$56	$58	$64	$516
Water	6	8	7	10	11	10	14	12	13	18	109
Land and Other	3	3	5	3	5	4	2	4	5	9	43
Total	$46	$58	$62	$66	$65	$59	$73	$72	$76	$91	$668

SOURCE: American Petroleum Institute, Environmental Expenditures of the United States Petroleum Industry, 1981.

TABLE 7

Total Environmental Expenditures of the Petroleum Industry -- 1971-1980
(Millions of Dollars)

	Year										Total
	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1971-1980
Air											
Capital	$391	$305	$436	$527	$601	$536	$339	$429	$561	$728	$4,853
Administrative, Operating, and Maintenance	143	198	251	352	389	635	792	864	997	1,392	6,013
Research and Development	37	47	50	53	49	45	57	56	58	64	516
Total	$571	$550	$737	$932	$1,039	$1,216	$1,188	$1,349	$1,616	$2,184	$11,382
Water											
Capital	$224	$184	$194	$271	$356	$411	$434	$340	$394	$527	$3,335
Administrative, Operating, and Maintenance	185	187	201	249	262	401	502	532	594	754	3,867
Research and Development	6	8	7	10	11	10	14	12	13	18	109
Total	$415	$379	$402	$530	$629	$822	$950	$884	$1,001	$1,299	$7,311
Land and Other											
Capital	$ 57	$51	$ 52	$ 97	$396	$269	$184	$ 89	$ 92	$183	$1,470
Administrative, Operating, and Maintenance	41	37	43	50	55	63	197	101	106	165	858
Research and Development	3	3	5	3	5	4	2	4	5	9	43
Total	$101	$91	$100	$150	$456	$336	$383	$194	$203	$357	$2,371
Air, Water, Land and Other											
Capital	$672	$540	$682	$895	$1,353	$1,216	$957	$858	$1,047	$1,438	$9,658
Administrative, Operating, and Maintenance	369	422	495	651	706	1,099	1,491	1,497	1,697	2,311	10,738
Research and Development	46	58	62	66	65	59	73	72	76	91	668
Total	$1,087	$1,020	$1,239	$1,612	$2,124	$2,374	$2,521	$2,427	$2,820	$3,840	$21,064

SOURCE: American Petroleum Institute, Environmental Expenditures of the United States Petroleum Industry, 1981.

TABLE 8

Environmental Capital Expenditures of the Petroleum Industry -- 1971-1980
(Millions of Dollars)

	Year										Total
	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1971-1980
Air											
Exploration and Production	$15	$17	$14	$27	$59	$85	$68	$59	$55	$123	$522
Transportation	8	3	10	22	37	30	26	20	15	33	204
Marketing	39	21	43	105	55	36	15	18	43	74	449
Manufacturing	329	264	369	373	450	385	230	332	448	498	3,678
Total	$391	$305	$436	$527	$601	$536	$339	$429	$561	$728	$4,853
Water											
Exploration and Production	$82	$68	$62	$92	$117	$135	$187	$206	$240	$316	$1,505
Transportation	20	16	22	37	84	57	45	38	35	50	404
Marketing	10	14	17	19	25	16	13	13	19	38	184
Manufacturing	112	86	93	123	130	203	189	83	100	123	1,242
Total	$224	$184	$194	$271	$356	$411	$434	$340	$394	$527	$3,335
Land and Other											
Exploration and Production	$13	$22	$27	$38	$57	$70	$54	$59	$63	$120	$523
Transportation	6	8	9	37	322	188	106	18	12	14	720
Marketing	11	14	8	6	4	3	3	4	3	14	70
Manufacturing	27	7	8	16	13	8	21	8	14	35	157
Total	$57	$51	$52	$97	$396	$269	$184	$89	$92	$183	$1,470
Air, Water, Land and Other											
Total	$672	$540	$682	$895	$1,353	$1,216	$957	$858	$1,047	$1,438	$9,658

SOURCE: American Petroleum Institute, Environmental Expenditures of the United States Petroleum Industry, 1981.

TABLE 9

Environmental Administrative, Operating, and Maintenance Expenditures of the Petroleum Industry -- 1971-1980
(Millions of Dollars)

	Year										Total
	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1971-1980
Air											
Exploration and Production	$8	$8	$12	$15	$20	$21	$28	$32	$35	$62	$241
Transportation	6	3		3		16	11	12	12	16	
Marketing	13	15	21	43	34	24	30	29	37	57	298
Manufacturing	116	172	214	291	328	574	723	791	913	1,262	5,384
Total	$143	$198	$251	$352	$389	$635	$792	$864	$997	$1,392	$6,013
Water											
Exploration and Production	$84	$66	$69		$87	$115	$141	$154	$173	$215	$1,194
Transportation	21	15	16	25	28	46	37	36	35	39	293
Marketing	5		7		11	13	13	22	19	24	128
Manufacturing	75	100	109	126	136	227	311	320	367	476	2,247
Total	$185	$187	$201	$249	$262	$401	$502	$532	$594	$754	$3,867
Land and Other											
Exploration and Production	$16	$16	$20	$24	$29	$27	$31	$38	$36	$52	$289
Transportation	5		8			14	128	24	18	19	241
Marketing	7	4		5	3	3	4	5	5		49
Manufacturing	13	8	10	13	15	19	34	34	47		279
Total	$41	$37	$43	$50	$55	$63	$197	$101	$106	$165	$858
Air, Water, Land and Other											
Total	$369	$422	$495	$651	$706	$1,099	$1,491	$1,497	$1,697	$2,311	$10,738

SOURCE: American Petroleum Institute, Environmental Expenditures of the United States Petroleum Industry, 1981.

TABLE 10

Development Expenditures [illegible] Industry
(Millions of Dollars)

	1971			1974	1975		1977				1971-1980
Air											
					$15						
									34		
Sampling and Testing	1				2	2	3	3	3	3	24
	$37										
Product	$2		$1		$3	$2	$4	$4	$3	$ 4	$27
Process				7		7		7		12	
Sampling and Testing	1			1		1		1	1		17
Total					$11		$14		$13	$18	
Land and Other											
Product	–	$1		–	$1	$1	–	–	$1	$2	$7
	1							3	3		23
Sampling and Testing		1	2	1	2	1	–	1	1	2	13
Total	$3			$3	$5	$4	$2	$4	$5	$9	$43
Air, Water, Land and Other											
Total	$46	$58	$62	$66	$65	$59	$73	$72	$76	$91	$668

SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry*, 1981.

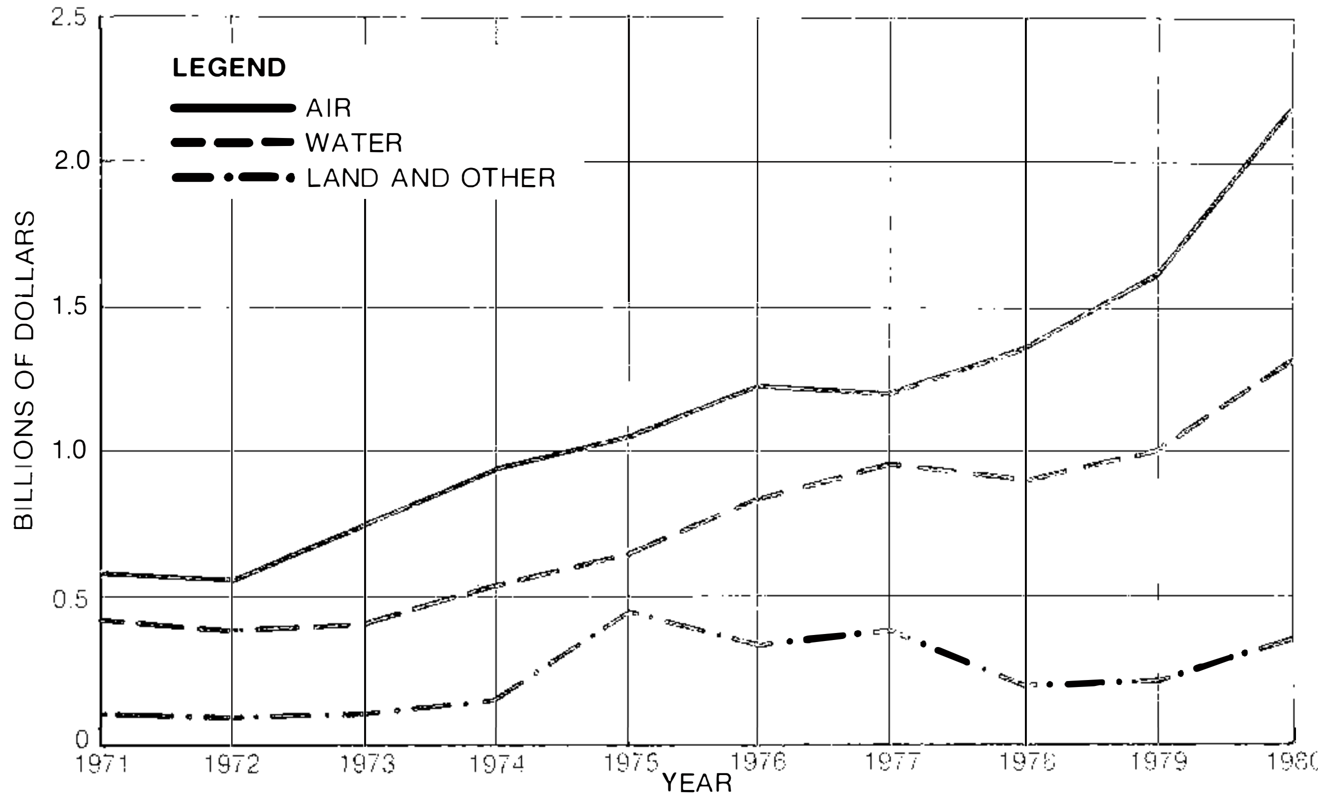


Figure 6. Total Environmental Expenditures of the Petroleum Industry—1971-1980.

NOTE: Data shown are as reported to API; they do not represent 100 percent of the expenditures.

SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry*, 1981.

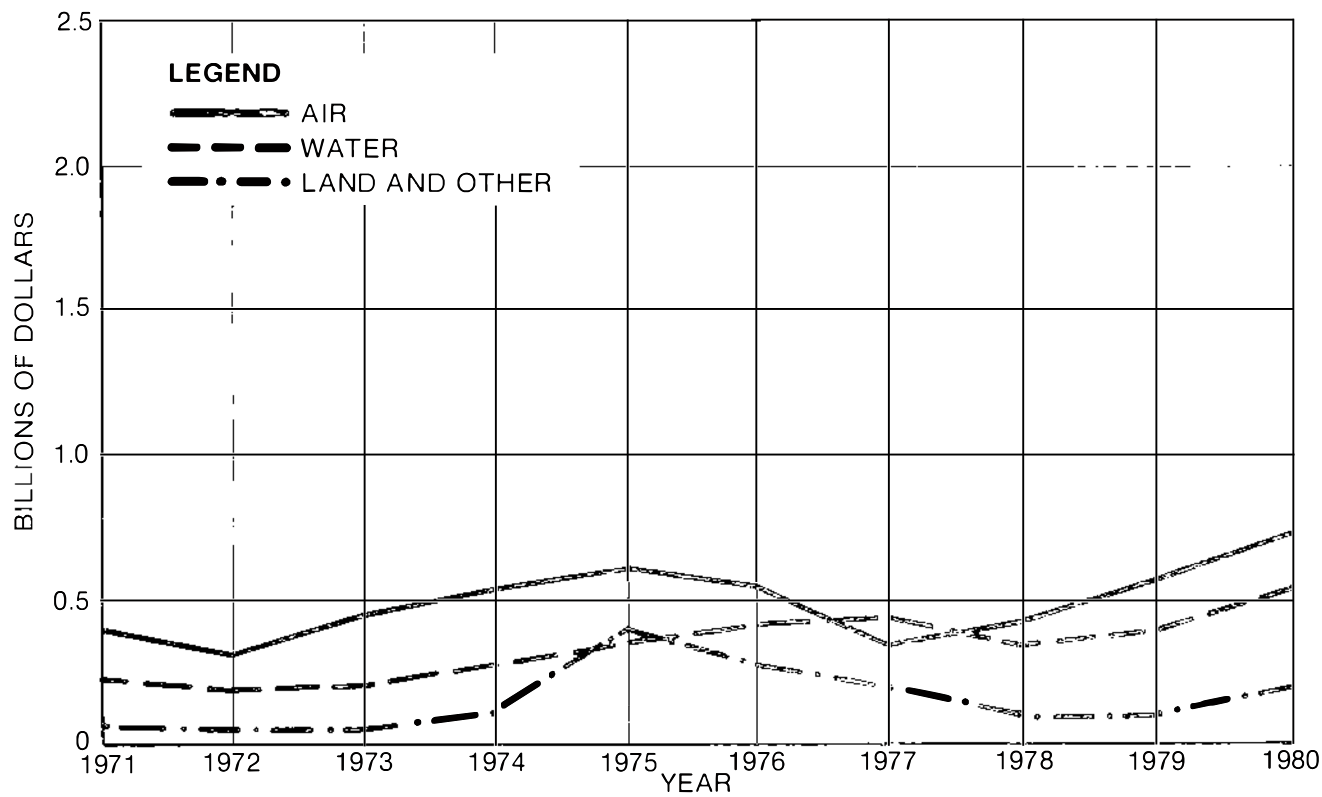


Figure 7. Environmental Capital Expenditures of the Petroleum Industry—1971-1980.

NOTE: Data shown are as reported to API; they do not represent 100 percent of the expenditures.

SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry*, 1981.

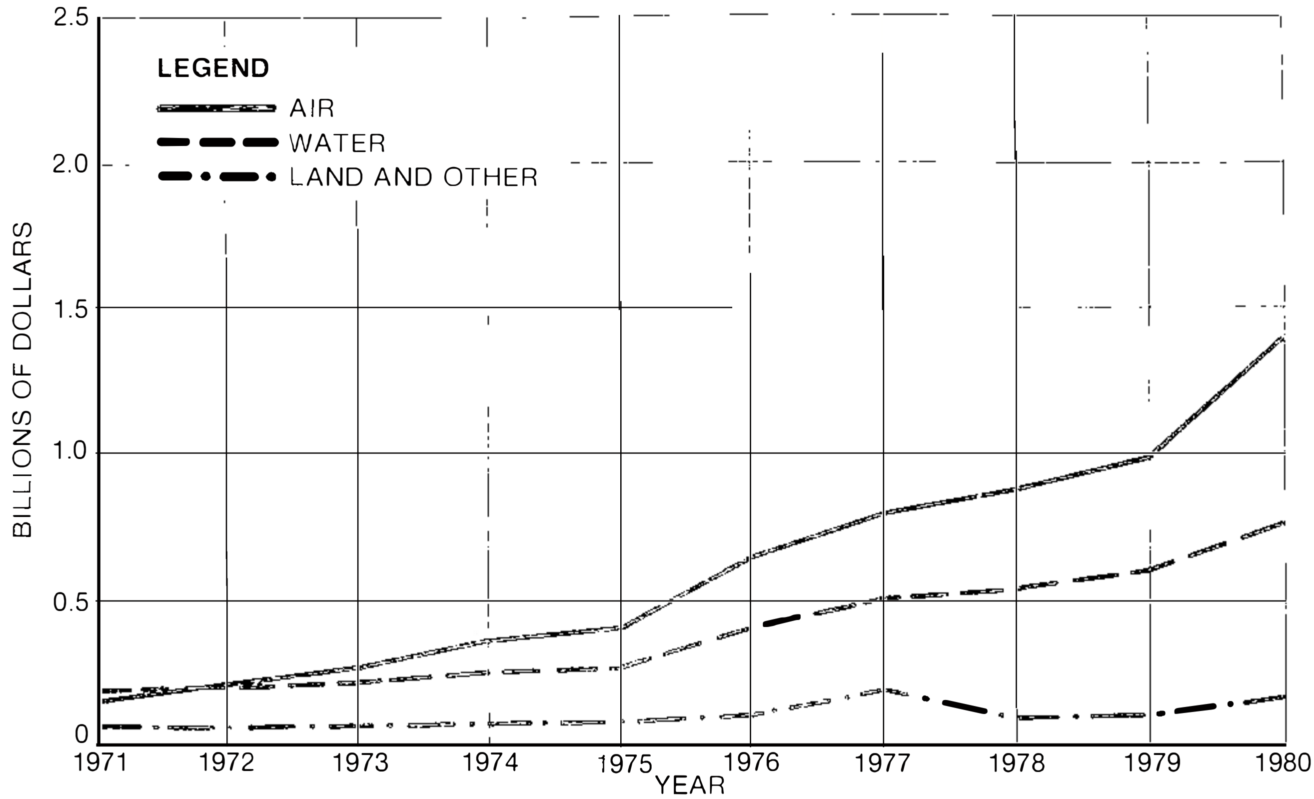


Figure 8. Environmental Administrative, Operating, and Maintenance Expenditures of the Petroleum Industry—1971-1980.

NOTE: Data shown are as reported to API; they do not represent 100 percent of the expenditures.
SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry*, 1981.

Tables 11, 12, 13, and 14 summarize the various analyses made during the study for all industry sectors, again excluding RCRA costs. The petroleum industry as a whole was forecast to incur an annualized cost of $13 billion in 1980 (1979 dollars), which will rise in 1990 to $17 billion plus RCRA costs. For additional details, see the Battelle report.

In order to put these expenditures and forecasted costs in some perspective, Table 15 shows the estimated incremental pollution expenditures for both the public and private sectors in the United States for the 1979-1988 period, as projected by the Council on Environmental Quality in 1980.[7] During the 10 years from 1979 to 1988, total spending in response to the federal environmental quality regulations is expected to total $518.5 billion.

TABLE 11

Total Annualized Costs of Environmental Regulations
to the Petroleum Industry -- 1970-1990*
(Millions of

	1970	1975	1980	1985 Anticipated	1990 Anticipated
Air					
Exploration and Production	$26	$88	$320	$600	$850
Transportation	--	23	73	80	110
Refining	540	3,400	5,300	5,900	5,800
Distribution and Marketing	--	220	310	350	330
All Sectors	560	3,700	6,100	6,900	7,100
Water					
Exploration and Production	$1,400	$2,400	$3,600	$4,900	$5,500
Transportation		42		410	440
Refining	290	1,000	1,900	2,100	2,200
Distribution and Marketing	--	48	180	180	180
All Sectors	1,700	3,500	5,800	7,600	8,300
Solid					
Exploration and Production	$23	$35	$45	$54	$40
Transportation	--	--	--	--	--
Refining	--	--	--	--	--
Distribution and Marketing	--	--	--	--	--
All Sectors	23	35	45	54	40
Other Pollution (e.g., Odor and Noise)					
Exploration and Production	$19	$19	$19	$19	$19
Transportation	1	65	82	82	81
Refining	2			810	830
Distribution and Marketing	--	--	--	--	--
All Sectors	22	130		910	930
All Pollution					
Exploration and Production	$1,400	$2,600	$4,000	$5,600	$6,400
Transportation	4	130	270	570	630
Refining	830	4,400	7,500	8,800	8,800
Distribution and Marketing	--	270	490	530	500
All Sectors	2,300	7,400	12,000	15,000	16,000
Unallocated					
All Sectors	$80	$160	$220	$230	$230
Grand Total	$2,400	$7,500	$13,000	$16,000	$17,000

*Excludes RCRA costs. Totals may not add due to rounding.

SOURCE: Battelle Columbus Laboratories, The Cost of Environmental Regulations to the Petroleum Industry, July 31, 1980.

TABLE 12

Cumulative Capital Investment Expenditures on Environmental Regulations by the Petroleum Industry -- 1970-1990*
(Millions of 1979 Dollars)

	1970	1975	1980	1985 Anticipated	1990 Anticipated
Air					
Exploration and Production	$76	$270	$820	$1,400	$2,000
Transportation	--	52	160	180	290
Refining	1,800	7,400	11,000	13,000	19,000
Distribution and Marketing	--	800	1,200	1,800	2,000
All Sectors	1,900	8,500	13,000	16,000	23,000
Water					
Exploration and Production	$4,700	$7,200	$11,000	$16,000	$21,000
Transportation	7	110	310	1,300	1,500
Refining	850	2,600	4,800	5,900	7,500
Distribution and Marketing	--	210	540	540	540
All Sectors	5,600	10,000	16,000	24,000	30,000
Solid					
Exploration and Production	--	--	--	--	--
Transportation	--	--	--	--	--
Refining	--	--	--	--	--
Distribution and Marketing	--	--	--	--	--
All Sectors	--	--	--	--	--
Other Pollution (e.g., Odor and Noise)					
Exploration and Production	$15	$90	$170	$240	$320
Transportation	6	260	330	330	330
Refining	1	180	1,200	2,900	3,000
Distribution and Marketing	--	--	--	--	--
All Sectors	22	530	1,600	3,500	3,700
All Pollution					
Exploration and Production	$4,800	$7,600	$12,000	$17,000	$23,000
Transportation	13	420	790	1,900	2,100
Refining	2,700	10,000	17,000	22,000	30,000
Distribution and Marketing	--	1,000	1,700	2,300	2,600
Grand Total	$7,500	$19,000	$31,000	$43,000	$57,000

*Excludes RCRA costs. Totals may not add due to rounding.

SOURCE: Battelle Columbus Laboratories, The Cost of Environmental Regulations to the Petroleum Industry, July 31, 1980.

TABLE 13

Annual Capital Investment on Environmental
Expenditures by the Petroleum Industry -- 1970-1990*
(Millions of 1979 Dollars)

	1970	1975	1980	1985 Anticipated	1990 Anticipated
Air					
Exploration and Production	$19	$78	$160	$120	$120
Transportation	--	32	--	26	1
Refining	1,500	610	1,000	213	390
Distribution and Marketing	--	390	52	150	33
All Sectors	1,500	1,100	1,200	500	550
Water					
Exploration and Production	$470	$610	$890	$1,000	$1,000
Transportation	7	44	13	205	22
Refining	170		130	200	410
Distribution and Marketing	--	3	--	--	140
All Sectors	640	1,100	1,000	1,400	1,400
Solid					
Exploration and Production	--	--	--	--	--
Transportation	--	--	--	--	--
Refining	--	--	--	--	--
Distribution and Marketing	--	--	--	--	--
All Sectors	--	--	--	--	--
Other Pollution (e.g., Odor and Noise)					
Exploration and Production	$15	$15	$15	$15	$15
Transportation		68	--	--	--
Refining	1	170	170	12	18
Distribution and Marketing	--	--	--	--	--
All Sectors	22	250	180	27	33
All Pollution					
Exploration and Production	$500	$700	$1,100	$1,100	$1,100
Transportation	13	140	13	230	23
Refining	1,700	1,300	1,300	430	820
Distribution and Marketing	--	390	52	150	33
Grand Total	$2,200	$2,500	$2,500	$1,900	$2,000

*Excludes RCRA costs. Totals may not add due to rounding.

SOURCE: Battelle Columbus Laboratories, The Cost of Environmental Regulations to the Petroleum Industry, July 31, 1980.

TABLE

Net Operating Costs of Environmental Regulations
to the Petroleum Industry -- 1970-1990*
(Millions of 1979 Dollars)

	1970	1975	1980	1985 Anticipated	1990 Anticipated
Air					
Exploration and Production	$8	$27	$140	$280	$420
Transportation	--	11	38	39	43
Refining	110	1,600	2,800	3,100	3,000
Distribution and Marketing	--		39	-50	-81
All Sectors	120	1,700	3,000	3,400	3,300
Water					
Exploration and Production	$320	$830	$1,200	$1,400	$1,400
Transportation	1	18	47	93	93
Refining	93	400	770	860	920
Distribution and Marketing	--	--	57	57	57
All Sectors	410	1,200	2,100	2,400	2,500
Solid					
Exploration and Production	$23	$35	$45	$54	$40
Transportation	--	--	--	--	--
Refining	--	--	--	--	--
Distribution and Marketing	--	--	--	--	--
All Sectors	23	35	45	54	40
Other Pollution (e.g., Odor and Noise)					
Exploration and Production	--	--	--	--	--
Transportation	--		8	8	8
Refining	--	7	51	130	135
Distribution and Marketing	--	--	--	--	--
All Sectors	--	13	59	140	140
All Pollution					
Exploration and Production	$350	$900	$1,400	$1,700	$1,900
Transportation	1	35	93	140	140
Refining	200	2,100	3,600	4,100	4,000
Distribution and Marketing	--	40	97	7	-26
All Sectors	500	3,000	5,200	6,000	6,000
Unallocated					
All Sectors	$80	$160	$220	$230	$230
Grand Total	$630	$3,200	$5,400	$6,200	$6,200

*Excludes RCRA costs. Totals may not add due to rounding.

SOURCE: Battelle Columbus Laboratories, The Cost of Environmental Regulations to the Petroleum Industry, July 31, 1980.

TABLE 15

Estimated Incremental Pollution Abatement Expenditures -- 1979-1988*
(Billions of 1979 Dollars)

Program	1979 Operation and Maintenance	1979 Annual Capital Costs†	1979 Total Annual Costs	1988 Operation and Maintenance	1988 Annual Capital Costs†	1988 Total Annual Costs	Cumulative (1979-1988) Operation and Maintenance	Cumulative (1979-1988) Capital Costs†	Cumulative (1979-1988) Total Costs
Air Pollution									
Public	$1.2	$0.3	$1.5	$2.0	$0.5	$ 2.5	$15.8	$3.7	$19.5
Private									
Mobile	3.2	4.9	8.1	3.7	11.0	14.7	32.1	83.7	115.8
Industrial	2.0	2.3	4.3	3.0	4.1	7.1	25.8	33.0	58.8
Electric Utilities	5.5	2.9	8.4	7.6	5.7	13.3	62.3	42.7	105.0
Subtotal	$11.9	$10.4	$22.3	$16.3	$21.3	$37.6	$136.0	$163.1	$299.1
Water Pollution									
Public	$1.7	$4.3	$6.0	$3.3	$10.0	$13.3	$25.1	$59.2	$84.3
Private									
Industrial	3.4	2.6	6.0	5.4	4.5	9.9	42.0	34.0	76.0
Electric Utilities	0.3	0.4	0.7	0.3	0.9	1.2	2.9	6.5	9.4
Subtotal	$5.4	$7.3	$12.7	$9.0	$15.4	$24.4	$70.0	$99.7	$169.7
Solid Waste									
Public	$<0.05	$<0.05	$<0.05	$0.4	$0.3	$0.7	$2.6	$2.0	$4.6
Private	<0.05	<0.05	<0.05	0.9	0.7	1.6	6.4	4.4	10.8
Subtotal	$<0.05	$<0.05	$<0.05	$1.3	$1.0	$2.3	$9.0	6.4	$15.4
Toxic Substances	$0.1	$0.2	$0.3	$0.5	$0.6	$1.1	$3.6	$4.6	$8.2
Drinking Water	<0.05	<0.05	<0.05	0.1	0.3	0.4	1.3	1.4	2.7
Noise	<0.05	0.1	0.1	0.6	1.0	1.6	2.6	4.3	6.9
Pesticides	0.1	<0.05	0.1	0.1	<0.05	0.1	1.2	<0.05	1.2
Land Reclamation	0.3	1.1	1.4	0.3	1.2	1.5	3.8	11.5	15.3
Total	$17.8	$19.1	$36.9	$28.2	$40.8	$69.0	$227.5	$291.0	$518.5

*Incremental costs are those made in response to federal legislation beyond those that would have been made in the absence of that legislation.

†Interest and depreciation.

SOURCE: Council on Environmental Quality, *Environmental Quality*, 1980.

REFERENCES AND NOTES

[1]Environmental Research and Technology, Inc., Effects of the Clean Air Act on Industrial Planning and Development, July 1981; Environmental Research and Technology, Inc., Impact of Air Quality Permits Procedures on Industrial Planning and Development, November 1980; National Council on Air Quality, To Breathe Clean Air, Report to the Congress, March 1981.

[2]Federal Register, 45 FR 52696.

[3]SCS Engineers, Assessment of Petroleum Industry Cost of Compliance With Proposed Hazardous Waste Regulations, 1979.

[4]These features are stated as optional annexes to the Convention; i.e., a state could adopt the Convention with or without any of these features.

[5]American Petroleum Institute, Environmental Expenditures of the United States Petroleum Industry, 1971-1980, 1981.

[6]Battelle Columbus Laboratories, The Cost of Environmental Regulations to the Petroleum Industry, July 31, 1981.

[7]Council on Environmental Quality, Environmental Quality -- 1980, December 1980.

CHAPTER TWO

EXPLORATION AND PRODUCTION

INDUSTRY OPERATIONS

U.S. RESOURCE BASE

ENVIRONMENTAL CONSIDERATIONS

CHAPTER TWO

EXPLORATION AND PRODUCTION

INDUSTRY OPERATIONS

INTRODUCTION

The many facets of oil and gas exploration and production operations are interrelated and interdependent, functioning concurrently for most of the life of a producing area, or field. The industry is composed of thousands of explorers and producers, and is supported by thousands of manufacturers, suppliers, and service contractors. The diagram in Figure 9 illustrates in simplified fashion the flow of activities from the time exploration starts, through the development of a commercial petroleum deposit, to field abandonment and the return of the land to its original use or a new use.

Exploration begins with geological and geophysical work and continues through the drilling and evaluation (logging) of several wells, most of which are nonproductive. It does not stop with the completion of a discovery well. Confirmation and extension wells are necessary to determine if a reservoir is of commercial quality and size. After a sufficient volume of producible oil and/or gas has been found, production facilities are installed, development wells drilled, transportation to markets arranged, and production is begun.

During the productive life of a field, it is often necessary to re-enter wells to do repairs and modifications such as production stimulation, control of produced waters, and control of formation sand intrusion. On initial completion, or when the natural reservoir pressure declines as oil is extracted and a well no longer flows, artificial lift devices, such as beam- and rod-supported subsurface pumps or gas lift facilities, are usually installed. Compressors are frequently used to increase the rate of production and extend the producing life of gas wells.

Throughout the productive life of a field, well and reservoir performance are studied. Remedial, stimulation, and recompletion work is performed and fluid or gas may be injected to maintain production. Wells may be deepened or supplemental wells drilled. There is a constant effort to sell or inject all produced natural gas. Water produced with the oil is separated, treated, and disposed of in a legally and environmentally acceptable manner either by injection into the ground or by discharge into surface water when permitted.

Gas produced with oil or from gas wells may contain enough heavier hydrocarbons (propane, butane, and natural gasoline) to economically justify extracting the natural gas liquids. Other produced gas may contain almost all light hydrocarbons (methane and

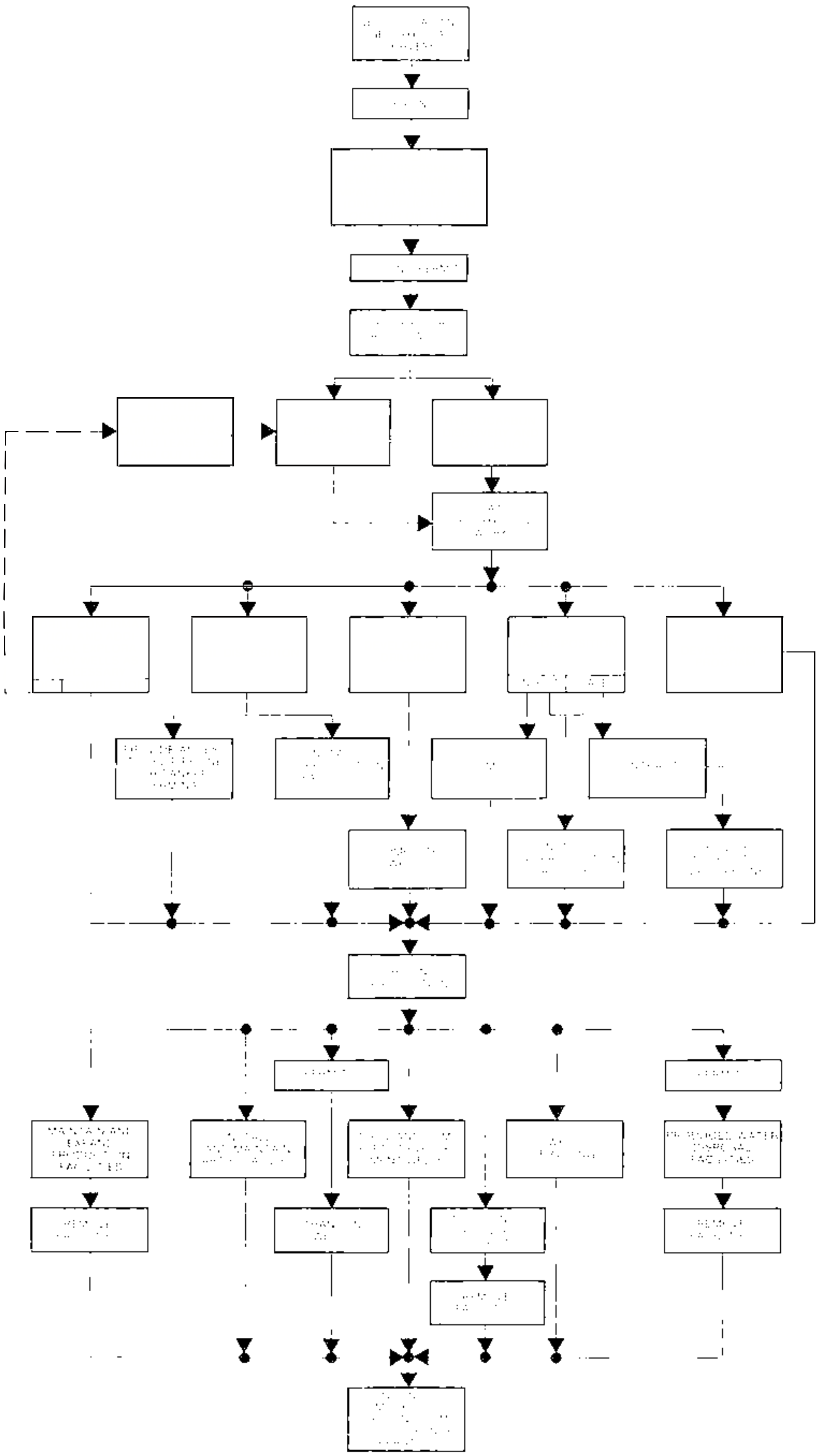


Figure 9. Simplified Flow Diagram Showing Operations for Exploration, Discovery, Production, and Abandonment of an Oil or Gas Field.

ethane) and is marketed without liquid extraction. Corrosive and toxic contaminants such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S) are separated for disposal before the gas is processed.

The productive life of many oil fields is extended by water flood or gas injection (secondary recovery). Some oil reservoirs can be revived for a third life (tertiary recovery) by injection of steam, CO_2, or chemicals (polymers, surfactants).

During the entire life of a field, maintenance work never stops. Artificial lift equipment must be serviced, surface facilities maintained, and replacement production and injection wells drilled. As wells become uneconomical to produce, they must be plugged with cement, salvageable casing pulled, surface equipment removed, and the surface area cleaned in accordance with the terms of the lease.

The length of time from the start of exploration until production begins may be from five to 10 years, while the productive life can be 25 to 50 years or longer.

Not shown in Figure 9 are the large number of permits and regulatory requirements, which add significantly to the effort, time, and cost of exploration and production operations. These requirements are discussed in the Environmental Considerations section of this chapter.

EXPLORATION

I. Geological

Exploration geology is fundamentally no different onshore, offshore, or in harsh climates. Study of exposed rocks at the surface can tell a geologist the history of the area, structural trends, and other information indicating whether proper conditions are present for the accumulation of hydrocarbons. In the search for petroleum, geologists usually look for the following essential information: the source beds of shales and limestones that originally contained an abundance of organic remains; the porous sandstones or limestones that later become the reservoir beds of migrating oil and gas; and the trap that seals off the reservoir beds and holds the hydrocarbons in place.

On land, rock samples may be gathered by hand or from shallow core holes. Continuous core drilling is no longer common because of costs, the great improvements in geophysical technology, and the increasing difficulty in securing permission to drill from land surface owners. Offshore, ocean floor samples are recovered by a grab device lowered from a vessel, or from shallow cores obtained by penetrating the ocean floor with a weighted tube or by jetting action, which can penetrate to about 75 feet. Core drilling to a maximum of 350 feet may be undertaken by special permit.

II. Photographic and Sonar Surveys

Aerial photographs of terrain taken at constant altitudes are interpreted and used to map surface geology, to aid in planning field visits, and to select sites for drilling and other surface facilities. Satellite photography, landsat imagery, image enhancement techniques, and side-looking radar have also been used for surveying.

Sonar (reflected sound wave) surveys are used to map the ocean floor in a manner comparable to onshore aerial photography. Sonar surveys can measure vertical water depth and, with side scan, reveal the dimensions of submarine ridges and trenches and the shape of the continental slope.

III. Geophysical

In the search for oil and gas, geophysical and geological studies are complementary. Geophysical measurements taken at the surface provide the major clues for locating potential subsurface reservoirs that may contain hydrocarbons. Sedimentary basins are first located and mapped by broad surveying techniques and their potential for hydrocarbon generation assessed; then structural traps where oil or gas could accumulate are identified.

Basins may be surveyed by airborne magnetometers, which measure small variations in the earth's magnetic field. Magnetic maps are used to map the basement surface (undisturbed igneous rock), although some anomalies can be mapped within the sedimentary sections.

Gravity surveys that measure small (up to one part per hundred million) variations in the total gravitational field of the earth can show the horizontal location of older, heavier, more deformed rocks within a basin of lighter, younger rocks. Gravity and seismic surveys are usually conducted at the same time.

Several other highly sophisticated geophysical techniques are used in basin surveys. Electrical transient measurement of a reflected pulsed electric signal generated at the surface can indicate variations in electrical resistivity, which is affected by the presence of hydrocarbons. The natural alternating currents (telluric) and small magnetic field eddy currents (magnetotelluric) can also be measured to indicate variations in the resistivity of rock layers. Magnetotelluric measurements can be related to rock porosity and salt water distribution.

The major geophysical technique used in oil and gas exploration is seismic reflection. Reflection surveys are usually made before the first exploration well is located and additional surveys help outline a field during development. A physical pulse or vibration created at or near the surface produces a wavefront of sonic energy, which travels through the subsurface and is partially reflected back to the surface each time the wavefront encounters a discontinuity such as the boundary between two rock layers. The

reflected energy is picked up at the surface by very sensitive microphones called seismometers or geophones, which convert the sonic energy into electrical energy that is then amplified to produce usable signals The seismograph records these signals as a function of elapsed time from the instant the pulse was created. Interpretation of the sonic wave travel time from the surface to one or more reflecting discontinuities and back to the surface at many locations furnishes data for subsurface contour maps. These maps and supporting geological data lead to identification of the most likely locations for hydrocarbon accumulation.

The physical pulse at the surface for seismic reflection has traditionally been created by firing a small explosive charge in a shallow borehole (50 to 200 feet deep). About one-half of land crews use this method. No explosive charges are used offshore. Modern technology has developed other seismic sources that are either more economical or have technical advantages: compressed air charges, which are used almost exclusively in marine seismic surveys; vibratory sources, which, because of economics, environmental considerations, and technical advantages, are the fastest growing explosives replacements on land; and a variety of other sources, such as weight drop and gas exploders, that are used for special applications. Compressed air charges discharged through holes drilled through floating ice are successfully used in the Arctic. The Beaufort Sea area adjacent to the coast and offshore to the vicinity of the ice pressure ridge (about 30-foot water depth) has been surveyed with precise results, using land crew equipment (vibrator sonic source) on the ice when the thickness was 48 inches or more.

The energy pulse released by a seismic generator is very weak and the energy received back at the surface is even weaker. It is difficult to recognize these reflection signals in the background of seismic noise. Modern interpretation methods include:

- Digital recording of data
- Computer processing to extract signal from noise
- Corrections for earth-induced errors
- Extraction from the signal of meaningful information and, in the best of circumstances, significant information about the hydrocarbon content of the reservoir rocks.

IV. Geochemical

Geochemistry, the science dealing with the chemical composition of and chemical changes in the earth's crust, makes a contribution to petroleum exploration through the following techniques:

- Helium is a minor constituent of natural gas. Because of its small atomic weight, it can pass upward through sedimentary rock and may be measurable in surface soil above hydrocarbon deposits.

- Sedimentary basins must be subjected to heat and pressure during geological time to generate hydrocarbons from buried organic material. Examination of the rocks can indicate the degree of maturity as a hydrocarbon source.

- The presence of minute amounts of hydrocarbons in formation waters can lead to predictions as to nearby hydrocarbon occurrences.

- The specific composition of the organic compounds that comprise a crude petroleum provides clues to its origin and migration history.

- Examination of rocks by scanning electron microscopes, by luminescence when heated, and by spectrochemical analysis for elemental composition, including the presence of heavy metals, can aid in identifying the matrix and the source of deposits within the pore space.

V. Continental Offshore Stratigraphic Test Wells

A Continental Offshore Stratigraphic Test (COST) well is an important source of information for exploration in U.S. Outer Continental Shelf (OCS) frontier areas. The U.S. Geological Survey (USGS) can authorize the drilling of a well by a group of companies to obtain geological information. All coring and logging information becomes proprietary to the participating companies, but is shared with the USGS in confidence until after the lease sale of the area of interest.

COST wells are located off-structure to avoid hydrocarbon accumulations and to obtain maximum stratigraphic information. The same USGS-OCS rules apply to securing permits and to drilling, casing, and abandonment for a COST well as apply to a regular exploration well. All COST wells must be plugged and abandoned when logging is completed. COST wells have been drilled in the Atlantic Georges Banks, Pacific offshore, Bering and Beaufort Seas offshore Alaska, Baltimore Canyon, and Gulf of Mexico.

DRILLING AND COMPLETION

I. Drilling Rigs and Drilling Operations

A rotary drilling rig is a portable apparatus designed to drill a hole into a geological formation and to wall the hole with steel pipe (casing) and cement, with the objective of exploring for and developing oil and gas fields. Portability limits rig design weight and size. Except for some specialized items such as fail-safe pressure control systems and the marine riser, the same kind of rig is used onshore and offshore. The rig support may be dry land, an inland submersible barge, an artificial island, a fixed structure, or a mobile offshore unit. Offshore exploration drilling is usually done by mobile units. Most offshore development drilling is done by controlled directional drilling from a fixed, bottom-founded platform.

The three main functions of all rotary drilling rigs are performed by the hoisting, circulating, and rotating systems, backed up by the pressure control equipment. Figure 10 shows the major components of the rotary drilling rig; each component is numbered to correspond with the discussion below.

A. Hoisting System

The mast or derrick (18) supports the hook (9) by means of the traveling block (10), wire line (11), crown block (12), and drawworks (14). These components are tied together and supported by a massive steel substructure (19). The drawworks are powered by prime movers (15), usually two to four engines. Most inland rig engines are diesel mechanical or electrical, and some are gas. Diesel-powered electric drives are common offshore; steam rigs are nearly obsolete.

During the drilling operation it is necessary to pull and rerun the drill pipe (4), to change bits (1), to run casing, and, if the well is successful, to run tubing. To perform these functions, elevators are suspended from the hook and are latched around the pipe below a coupling or drill pipe tool joint so that the pipe-string may be hoisted.

B. Circulating System

Drilling-fluid materials (muds) are mixed through the mud-mixing hopper into the mud tanks (17). From these tanks the mud is pumped down the drill pipe (4) via the swivel (8) and kelly (6). This mud exits the drill pipe through the drilling bit and returns to the surface through the annulus (space between the well bore wall and the drill pipe). As the mud travels up the annulus, it carries the drill cuttings in suspension to the mud return line. The mud is then passed through the solids control equipment (shale shaker screens, hydroclones, etc.) to remove the cuttings and is returned to the mud tanks for recirculation. Figure 11 shows a flow diagram depicting the route drilling mud travels during the drilling of a well.

Some of the functions performed by drilling muds are as follows:

- Remove drilled solids (cuttings) from the bottom of the hole and carry them to the surface where they are removed
- Lubricate and cool the drill bit and string
- Deposit a semi-impermeable wall cake on the well bore wall to seal permeable formations and prevent the loss of drilling mud into the formation
- Control downhole pressures by maintaining a fluid column pressure greater than drilled formation pressure
- Suspend drill cuttings in the fluid when circulation is interrupted

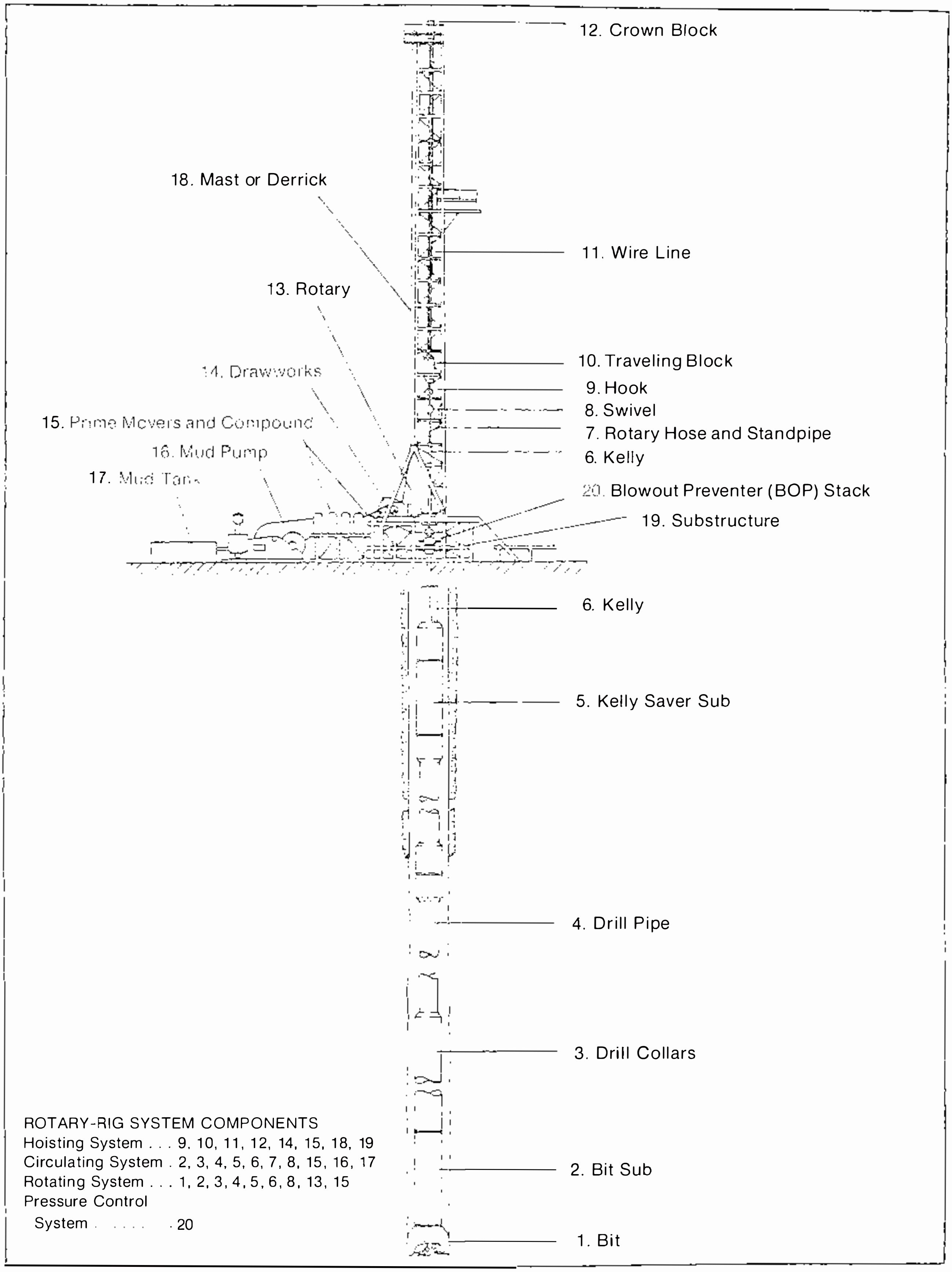


Figure 10. Systems and Components of a Rotary Drilling Rig.

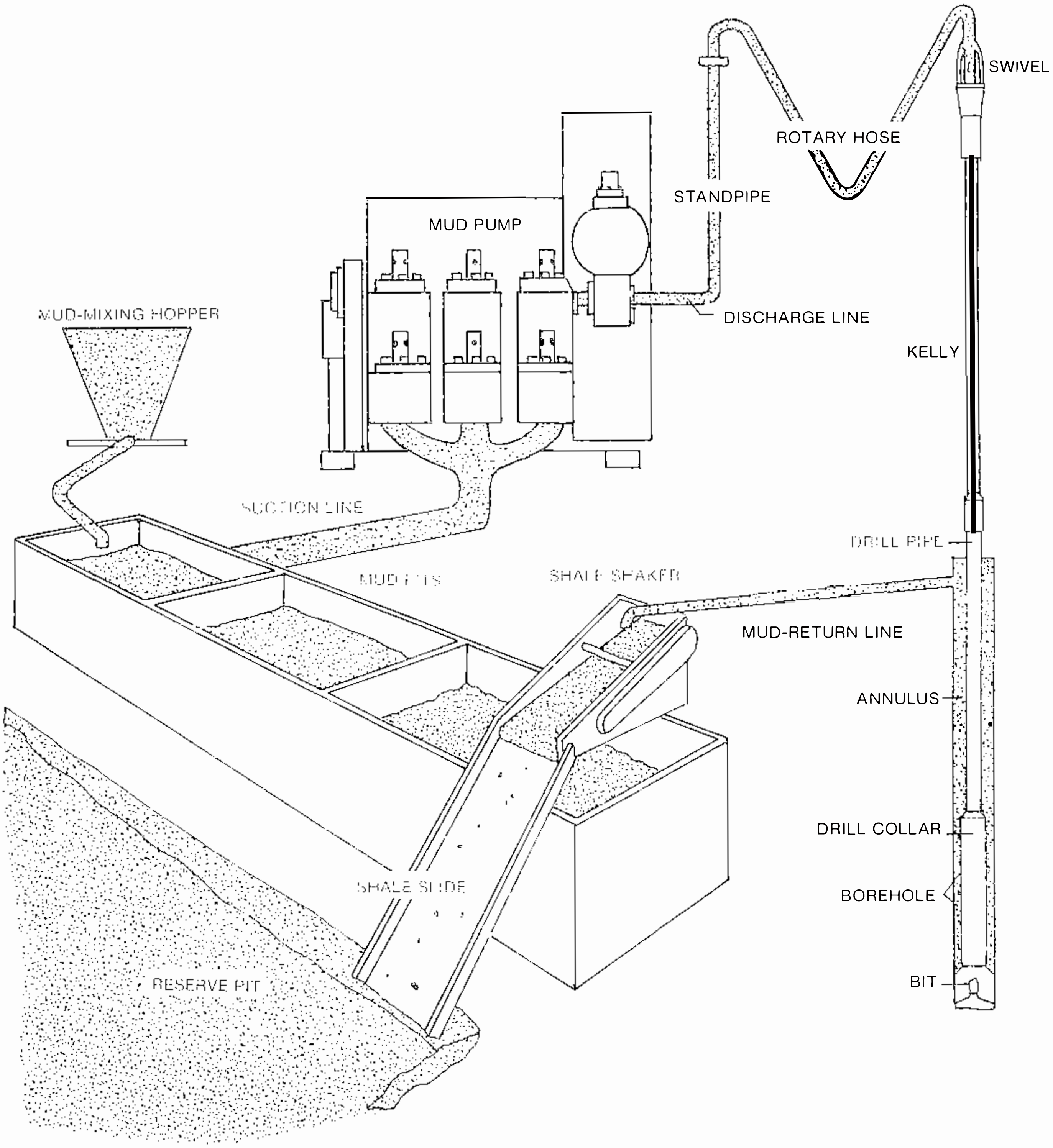


Figure 11. Route of Drilling Muds.

SOURCE: Moseley, H.R., Jr., *Chemical Components, Functions, and Uses of Drilling Fluids,* paper presented at United Nations Environmental Programme Environmental Consultative Committee on the Petroleum Industry, Paris, France, June 1981.

- Support part of the weight of the drill bit and string
- Transmit hydraulic horsepower to the bit.

To accomplish these many functions under extreme variations in formation pressure, temperature, and formation integrity requires drilling mud programs designed for local conditions and close surveillance by trained personnel. To produce the desired muds, which may vary in weight from 9 to 18 pounds per gallon, the most common materials added to the natural drilling fluid generated by drilling with water are:

- Attapulgite clay to build up fluid volume
- Barite (a barium sulfate) to add weight
- Bentonite (sodium montmorillonite) to add viscosity, or thicken
- Lignosulfonates (paper mill by-product) to lower viscosity, or thin
- Starch, calcium chloride, soda ash, and caustic soda to control fluid loss into permeable formations
- Fibrous and granular inert material to plug extremely porous or fractured formations
- Bactericide to prevent deterioration of starch muds
- Inhibitors to minimize corrosion in deep, high-temperature wells.

Fresh water is the usual liquid used for drilling shallow wells. Deeper wells, which penetrate high-pressure and high-temperature formations, may require complex, high-density drilling fluids with a liquid that may be salt water, oil emulsion, or oil. Other special wells may use air or foam as the circulating medium.

Surplus and contaminated mud are pumped into an earthen reserve pit or steel tank for later disposal as described in the Environmental Considerations section of this chapter.

C. Rotating System

The rotary, powered by prime movers, rotates the kelly through the kelly drive bushing, which rests in a square recess in the rotary. The kelly, a flat-sided, usually hexagonal hollow forging, 40 to 45 feet long, is suspended by the swivel and hoisting machinery during drilling operations. It is free to move vertically through the kelly drive bushing and serves to suspend and rotate the drill pipe. When drilling or circulating operations are suspended for the bit to be pulled or casing run, the swivel, kelly, and kelly drive bushing are removed. A device called slips is placed in the rotary recess around the drill pipe to suspend it,

when not being lifted by the elevators, while running in or pulling out of the hole.

Drill pipe is the steel tube used to transmit rotating force from the rotary, located on the derrick floor, to the drill bit on the bottom of the hole. The rotating force and weight of the drill collars below the drill pipe provide directional control and cutting power to the bit. When pulled from the hole, the drill pipe rests on the derrick floor in stands, which are usually three 30-foot joints connected by coarse threaded couplings of high strength, abrasion-resistant steel, called tool joints. Throughout the drilling operation, drilling fluid is pumped down through the drill pipe and back up the annular space to the surface.

D. Pressure Control System

Pressure control equipment seals a drilling well at the surface of the hole below the derrick floor, to prevent unwanted flow from the well, either through the annulus around the drill pipe or while the drill pipe is out of the hole.

The blowout preventer (BOP) stack (20) attached to the casing head at the top of the well consists of combinations of annular and ram-type BOPs, activated by hydraulic controls located at a safe distance from the well bore. Figure 12 is a schematic drawing of a conventional BOP stack installed on a land- or bottom-founded off-shore platform casing head.

BOPs are made in pressure ratings compatible with wellhead pressure and drilling requirements in a wide range of sizes. The annular BOP, usually located on top of the BOP stack, closes circumferentially. It can seal around any size pipe that can go through it, around the hexagonal kelly, or to a limited extent close the open hol   Ram-type BOPs seal around the pipe by radial movement of preformed half-circle rubber blocks embedded in two steel rams or plungers mounted in the BOP body on opposite sides of the hole. The rams must be sized to fit the drill pipe being used. Blank rams are fitted with straight parallel rubber blocks for use when the drill pipe is out of the hole. Special designs for ocean floor installation are necessary for floating platform rigs.

As a safety device to prevent backflow through the drill pipe while drilling, a kelly valve is installed on all drilling rigs at the top of the kelly, immediately below the swivel, where it can be closed in an emergency. A back pressure valve equipped with tool joint threads is kept on the derrick floor during drilling operations so that it can be screwed into the drill pipe if the well starts to backflow while the kelly is disconnected. Some rigs also use a drop valve that can be pumped down the drill pipe to shut off flow at the bottom.

Hydraulic fluid for opening and closing BOPs is stored in a pressure accumulator located a safe distance from the rig floor. High-pressure lines carry the hydraulic fluid from the accumulator to the BOP stack, and when control valves on the rig floor are

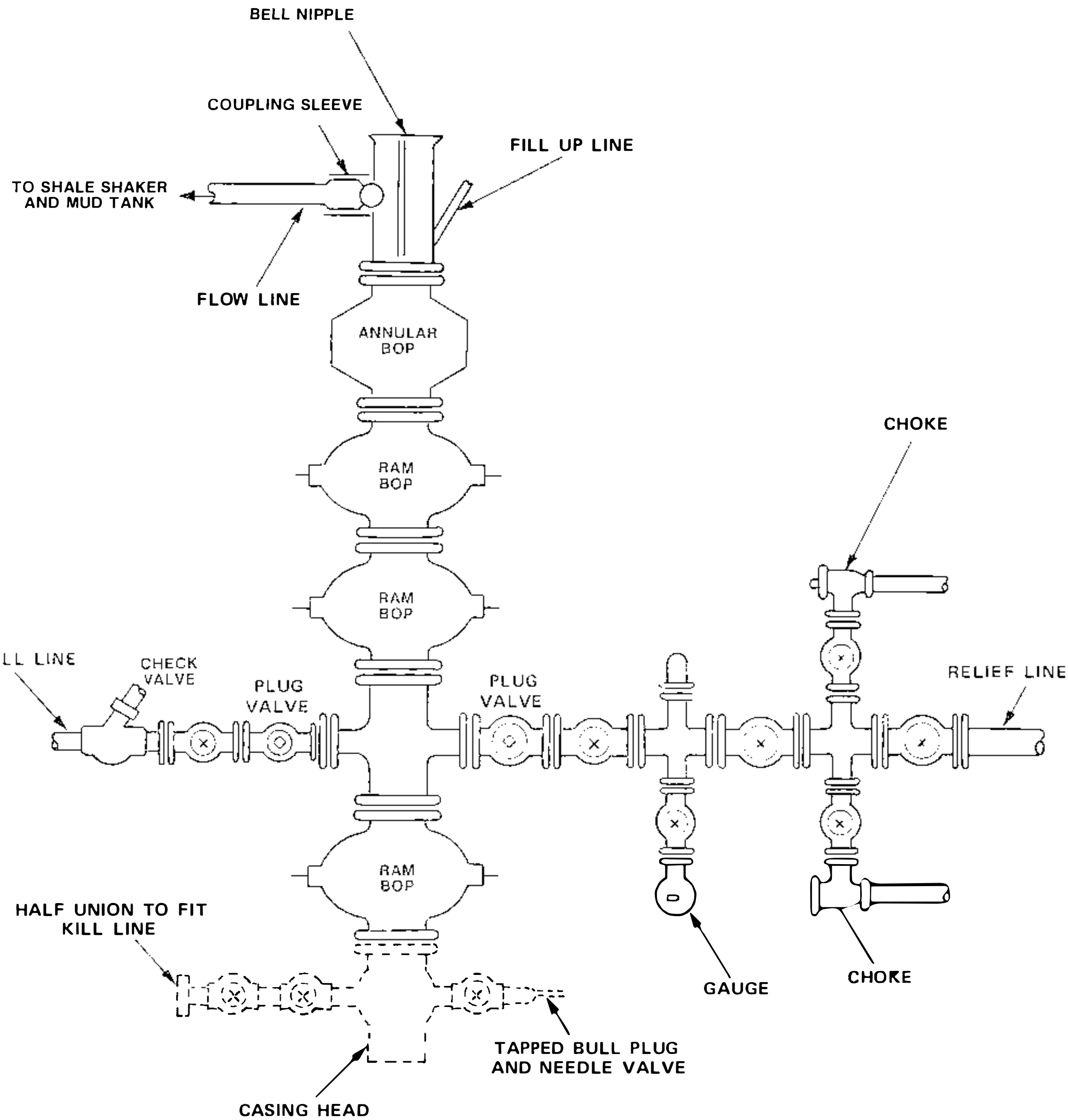


Figure 12. Conventional Blowout Preventer Assembly.

actuated by the driller, the fluid operates the BOPs. The hydraulic fluid is under pressures ranging from 1,500 to 3,000 pounds per square inch (psi).

E. Casing and Cementing

All wells are cased with steel pipe during drilling and completion. Figure 13 shows the casing strings installed in a typical deep well, onshore or offshore, exploratory or developmental. Except for the first string set offshore, which is driven into the

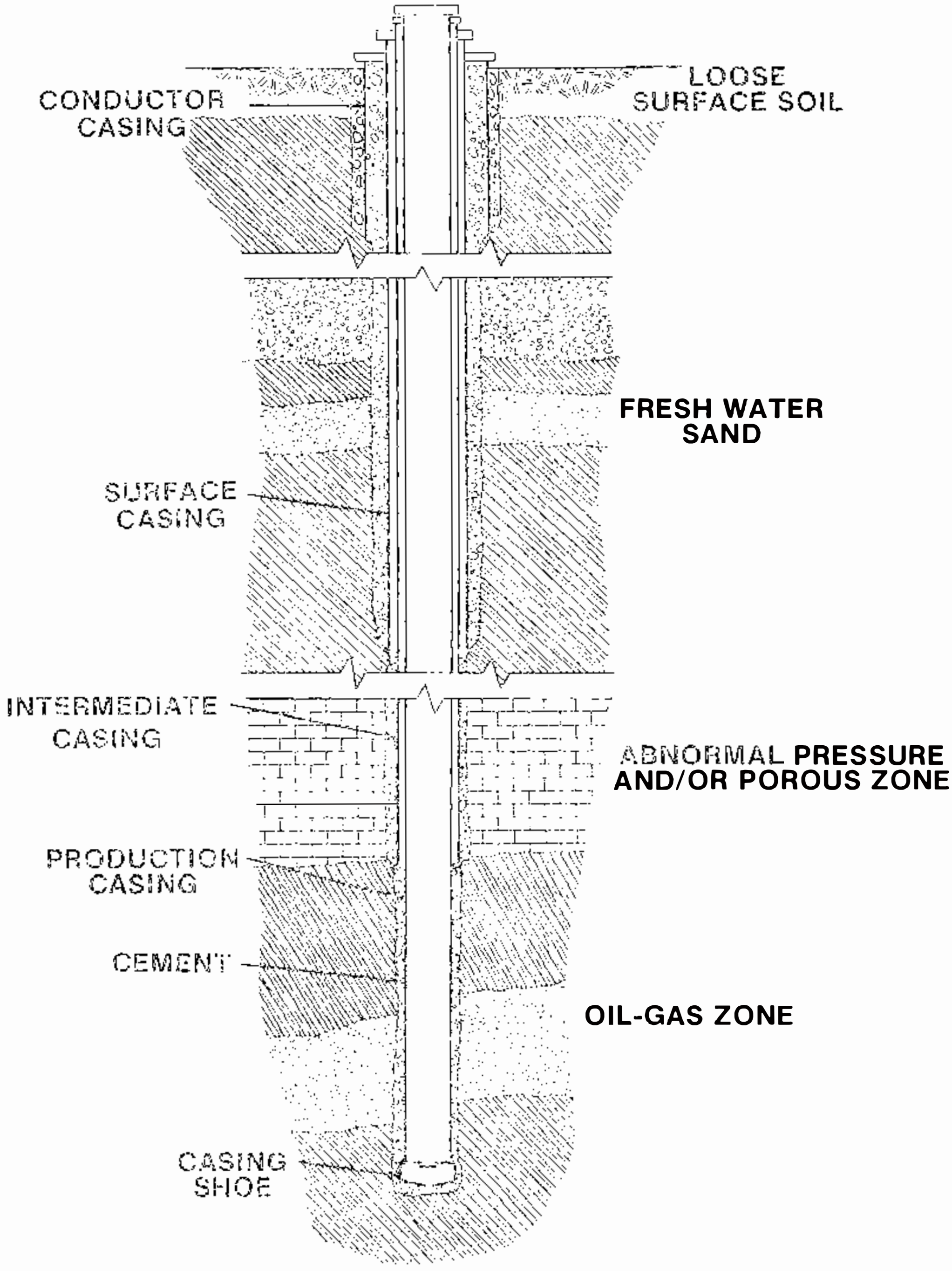


Figure 13. Casing Strings.

ocean floor, casing is lowered into the drilled hole and cemented in place by pumping cement down the pipe and back up the annular space.

Drive pipe used offshore (not shown in Figure 13) is typically 26 inches in diameter and is driven to 100 feet below the ocean floor to support the annular BOP and the diverter head at the surface, which directs drilling fluid to mud tanks while drilling for conductor casing.

The conductor casing, usually 20 inches in diameter, is set at depths of 500 to 1,000 feet in offshore operation and is cemented to the surface. It supports the annular BOP and diverter head while drilling the surface casing hole. Conductor casing is not necessary in development well drilling where it is known that surface formations are competent and there are no shallow gas zones.

Surface casing is set through fresh water zones to prevent their contamination and to contain potential fluid flow from high-pressure zones penetrated below the surface casing. It is usually 13-3/8 inches in diameter offshore and in deep or exploratory wells onshore; it is set at depths of 1,500 to 4,500 feet, depending upon formation conditions, and is cemented to the surface. Surface casing for shallow to moderately deep development wells (8,000 to 10,000 feet) is usually 9-5/8 or 10-3/4 inches in diameter.

Intermediate casing is set when abnormal pressure (significantly above 0.5 pounds per foot of depth) is anticipated. Intermediate casing, usually 8-5/8, 9-5/8, or 10-3/4 inches in diameter, is cemented up through an impermeable zone above the abnormal pressure zone. The purpose is to prevent the heavy drilling fluid that is required to control abnormal pressure from entering shallow, low-pressure permeable zones.

Production casing is set through oil and gas zones that are to be completed for production, and cemented up into an impermeable zone. All potentially productive zones are covered with cement. Production casing is usually 4-1/2 to 7 inches in diameter.

F. Emissions and Effluents

Generally, the only air emissions during normal drilling operations are exhausts from internal combustion engines, crew quarters water heaters, and space heaters. Diesel fuel is used almost universally. During the rare drill stem testing of a well, very small volumes of natural gas may be emitted unburned.

Discharges requiring disposal during normal drilling operations onshore and offshore are:

- Excess drilling fluid generated by the addition of water, chemicals, and solids to maintain necessary physical properties.
- Drill cuttings excavated during hole making.
- Degradable kitchen garbage.
- Domestic graywater wastes (showers, lavatories, kitchen sink, laundry).
- Sanitary wastes (toilets, urinals).
- Waste oil and petroleum products (held for disposal at waste oil sites onshore).

- Other solid wastes such as wire lines, junked pipe and equipment, cans, glass, wood, paper, plastic, rubber, and rope (held for disposal at proper solid waste disposal sites).

On offshore drilling platforms, there are discharges of seawater used to cool various internal combustion engines and heat exchangers that are returned to the sea without additives other than heat.

Industry practices and regulatory requirements for the prevention of pollution by the above emissions and effluents are discussed in the Environmental Considerations section of this chapter.

II. Onshore Drilling

Onshore drilling is normally done from single locations, with the hole drilled as nearly vertical as feasible. Exceptions are environmentally sensitive areas such as the Alaskan North Slope, urban areas such as Los Angeles, and coastal locations such as southern California. In such circumstances, well drilling sites are closely spaced at an acceptable spot and wells may be drilled by controlled directional techniques to remote reservoirs, which may be bottomed several thousand feet horizontally from the surface locations.

In rural and less sensitive areas, drilling rigs are laid out in as compact an array as possible. A deep exploratory rig requires about 1.5 acres. If a reserve pit for excess drilling fluid is used, as is normal, it will occupy another 1.5 acres, for a total of about three acres. The average exploratory drilling rig occupies about two acres, and the average development drilling rig about one acre. A permanent clearing of about one-third of an acre is needed around a deep producing well to accommodate a well servicing rig.

Land rigs are moved by heavy trucks, rigged up by mobile cranes, and continuously served by wheeled vehicles requiring adequate roads. Road right-of-way to a drill site generally varies from 20 to 30 feet wide or about 3 acres per mile. If an exploratory well is dry, the roadway may be left intact or restored, in accordance with agreement with the landowner. Swamp locations require special dredge and fill permits for building access roadways.

III. Offshore Drilling

A. Exploration Drilling

Almost all exploration drilling offshore is done with mobile units. The type of mobile rig used is usually dependent on water depth, sea conditions, and weather. The four principal types (submersible, jack-up, drill ship, and semisubmersible) are described below. The marine riser and pressure control equipment are also discussed in this section.

1. Submersible Rig

A submersible is a barge-like vessel supporting a drilling rig and its equipment. It is towed to location and submerged to sit on the ocean floor, where it serves as a fixed platform. It typically operates in shallow (25 to 50 feet), calm waters. Submersible rigs were the forerunners of the present generation of mobile rigs, and their functions have been largely assumed by jack-up rigs. Many submersible barge rigs are still used in shallow (6 to 10 feet) inland water and marsh operations. Again, special dredge and fill permits are required to cut slip canals in the marsh to float the barge onto location.

2. Jack-Up Rig

Jack-up (self-elevating) rigs (Figure 14) have retractable legs, which are lowered to the ocean floor and enable the body (hull) of the platform to be raised to a safe distance above the sea surface. Some jack-up rigs have their legs attached to a mat to support the rig weight on the ocean floor, but most designs carry the load on bottom leg cylinders. When the rig is to be moved, the platform is lowered into the water, the legs retracted, and the entire unit floated by platform hull buoyancy. Jack-up rigs may be self-propelled but are usually moved by tugs.

Drilling can be conducted from a jack-up rig in more severe weather than typical floating rigs and several wells can be drilled directionally from one location. This is the most widely used mobile rig in waters up to 300 feet deep.

3. Drill Ship

A drill ship (Figure 15) is a free-floating, ship-shaped vessel that is kept in position by multiple anchors or by dynamic positioning with propeller thrusters. Drill ships have several advantages, including proven deepwater capability, capacity to transport large loadings of drilling supplies, fast travel time to remote locations, and relatively low operating costs. One disadvantage of a drill ship is its limited capacity to operate in wind and wave conditions that produce excessive rig motion. The limiting factor is about 15 feet of heave, which can be tolerated by the marine riser tensioning and heave compensating devices.

The operational water depth for a drill ship is limited to about 4,500 feet by the ability to handle the length of marine riser. Deep exploration wells have been drilled in water depths of 4,000 feet from moored and dynamically positioned drill ships.

4. Semisubmersible Rig

A semisubmersible platform (Figure 16) is supported by a pontoon hull, which is at the sea surface during transport. When in the drilling mode, the hull is submerged below the wave troughs and the platform remains above the wave crests. Stability is maintained by caisson legs which connect the hull to the platform. The

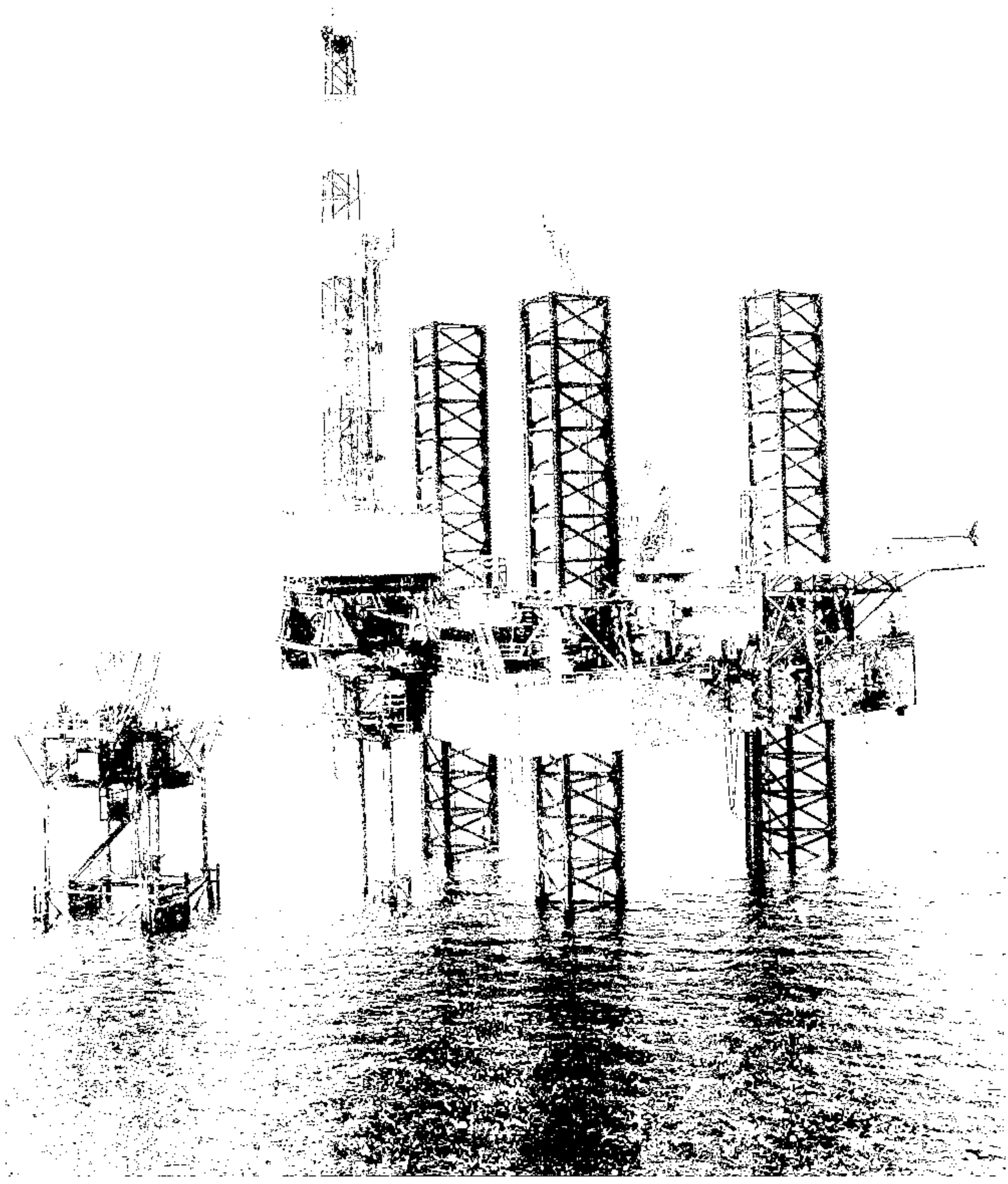


Figure 14. Jack-Up Drilling Rig.
SOURCE: Marathon Manufacturing Company.

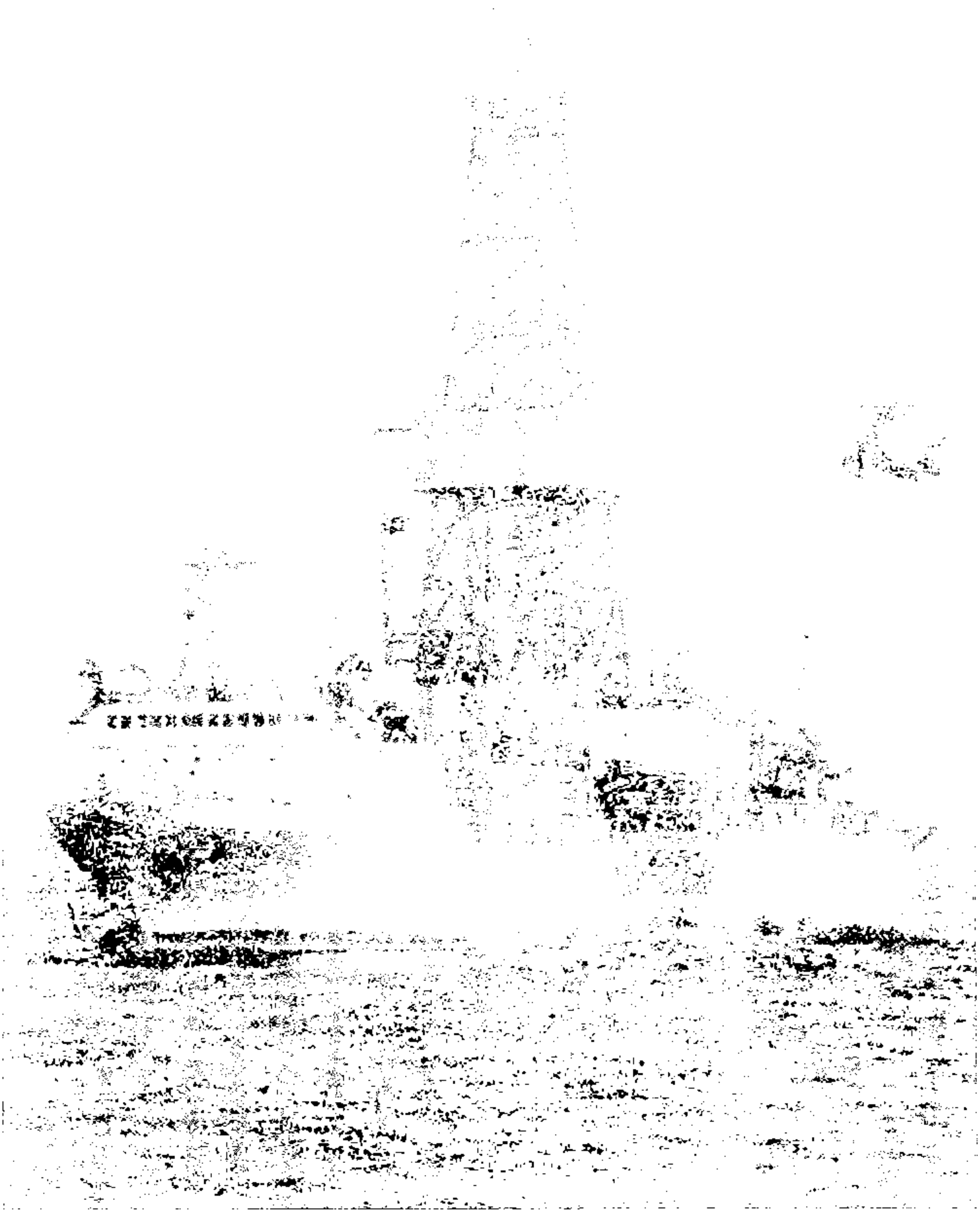
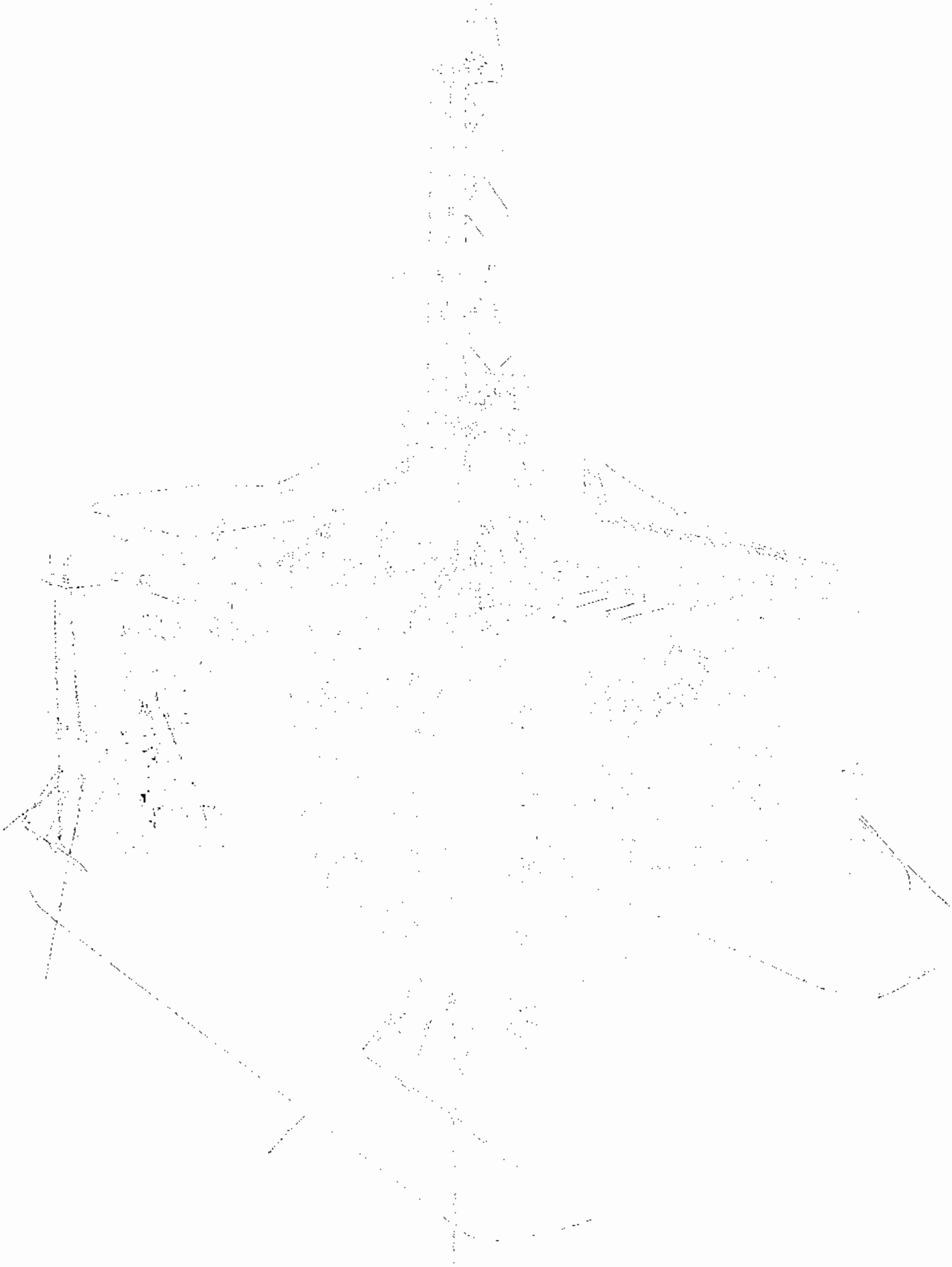


Figure 15. Drill Ship.

SOURCE: The Offshore Company.



SOURCE: Bethlehem Steel Corporation.

unit is held in drilling position by anchors or by computer-controlled propeller thrusters. Advantages of a semisubmersible are its deepwater capability, platform stability, operating performance in inclement weather, and good mobility. It is the favored exploration drilling unit in the North Sea, North Atlantic, and offshore Alaska.

While the semisubmersible can tolerate rougher seas than a drill ship, its operational limiting factor while drilling is the same as a drill ship, about 15 feet of heave. The semisubmersible heave response to wave action is less than a drill ship, however, because of less water plane area, except when wave swell frequency coincides with the vessel's natural frequency.

The operational water depth for a semisubmersible, as with a drill ship, is limited by the ability to handle the marine riser, which is from 4,000 to 4,500 feet. Semisubmersibles do not have as much deck load capacity to store and transport a long marine riser as does a large drill ship.

5. Marine Riser and Pressure Control Equipment

The marine riser is the heavy wall pipe that connects the ocean floor BOP stack to the BOP and mud flow lines under the derrick floor of a floating drilling rig. The usual size of a marine riser is 18-5/8 inches outside diameter, to which is added flotation material to make the riser partially self-supporting.

Marine risers must maintain internal pressure integrity between the BOP fixed to the wellhead on the ocean floor and the derrick floor BOP, which can move with the floating rig six ways in three dimensions:

- Surge -- longitudinal translation
- Roll -- longitudinal rotation
- Sway -- transverse translation
- Pitch -- transverse rotation
- Heave -- vertical translation
- Yaw -- vertical rotation.

Heave of the drilling unit as it rises and falls with sea swells plus the vertical components of surge and sway are allowed for in the riser slip joint and the drill pipe motion compensator.

The horizontal components of surge and sway and the bending effects of roll and pitch on the riser are accommodated in a ball joint immediately above the ocean floor BOP stack and in flexibility of the riser pipe. Drill pipe has sufficient flexibility to allow this motion without damage. Rotation due to yaw is allowed in the riser slip joint. The motion compensator above the swivel

can allow for as much as 20 feet heave without lifting the bit off bottom. Operational good practice is limited to about 15 feet heave. Bumper subs (sliding sleeve drill collars) can be used on bottom to increase heave tolerance or as an emergency substitute for the motion compensator.

The ball joint used by most floating units allows 10 degrees movement in any direction from vertical, which is adequate for drilling to continue during a 6 percent water depth horizontal excursion and for an 8 to 10 percent excursion with the riser attached but not drilling.

The water depth technical limit for marine risers of about 4,500 feet is not caused by the riser design; it is the inability of floating drilling units to transport and handle a longer string of this large heavy pipe.

Pressure control equipment for floating rigs is the same as above-water equipment except for the redundancy required by the ocean floor location and the need for fail safe remote control. The typical above-water BOP stack shown in Figure 12 has one annular BOP, two ram-type BOPs equipped with pipe rams, and one ram-type BOP with blind rams. A typical ocean floor BOP stack (Figure 17) has four pipe ram BOPs; one blind ram BOP equipped with shears capable of severing the drill pipe; and two annular BOPs, one above and one below the riser connector.

All ocean floor BOP operations are performed by hydraulic power controlled from the surface. Controls may be hydraulic or electric. As a minimum, two independent signal conductors and two independent power lines are provided. The BOP stack is lowered to the ocean floor and retrieved on the marine riser, suspended by the rig hoisting machinery, and usually guided into place on the wellhead by wire lines stretched from the rig to an ocean floor base.

An offshore exploration well may be permanently plugged and abandoned. If it is a commercial discovery, it may be temporarily plugged, the mobile rig moved, and a fixed platform built above it for development drilling and production. In any case, the ocean floor BOP stack is removed with the marine riser since it is part of the drilling rig equipment.

B. Development Drilling Platforms

Offshore development drilling is usually done from a fixed structure. Almost all operations in U.S. waters are from pile-founded steel platforms such as shown in Figure 18. The water depth limit for steel platforms is more economic than technical. Designs have been extended to serve large fields as discovered in increasingly deep water. A steel platform is in operation in more than 1,000 feet of water in the Gulf of Mexico.

Concrete platforms, constructed onshore, floated to offshore locations, sunk and held in place by gravity, are being successfully used in the North Sea. Monopod concrete structures are

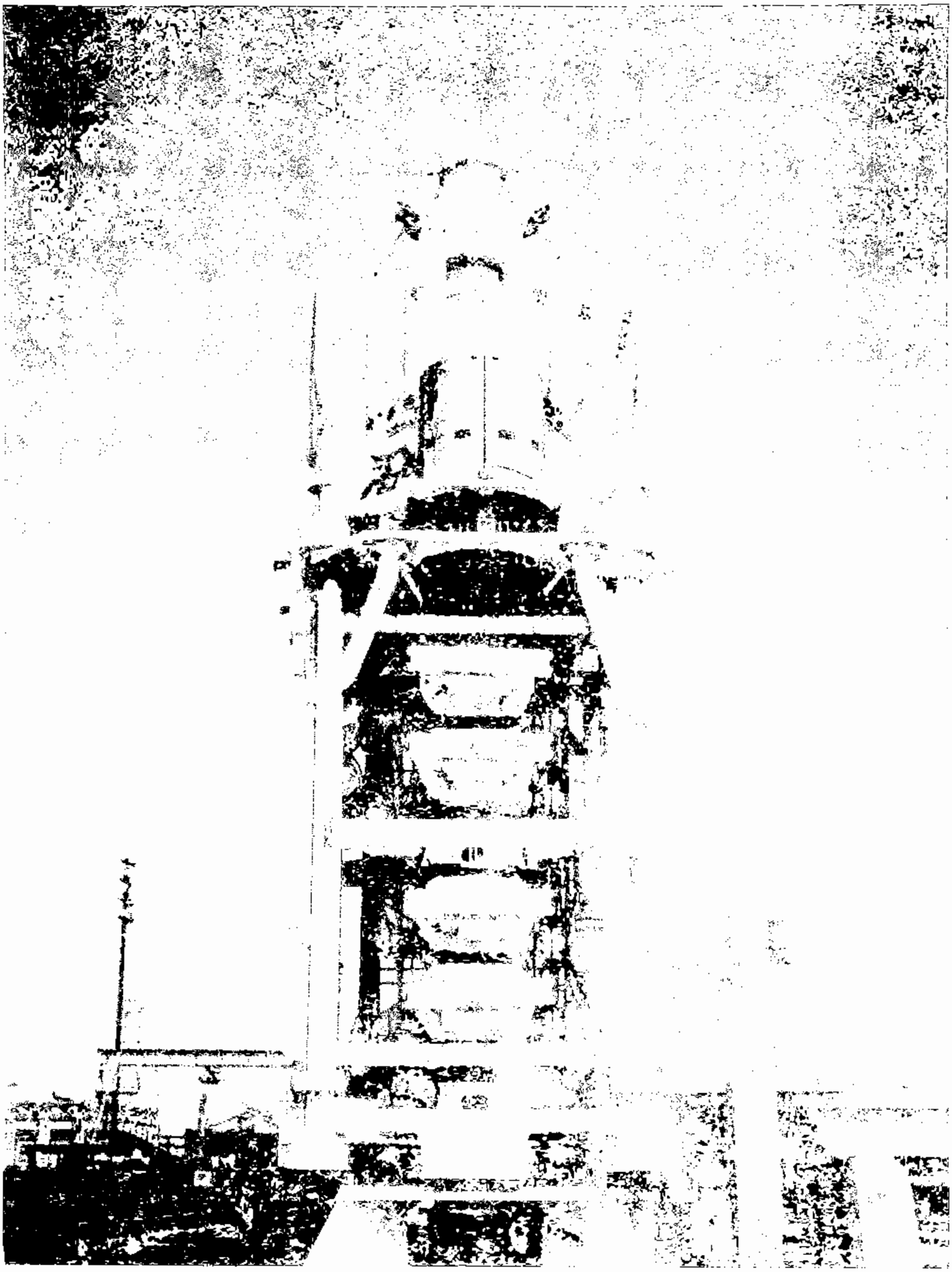


Figure 17. Ocean Floor Blowout Preventer and Marine Riser.

SOURCE: Cameron Iron Works, Inc.

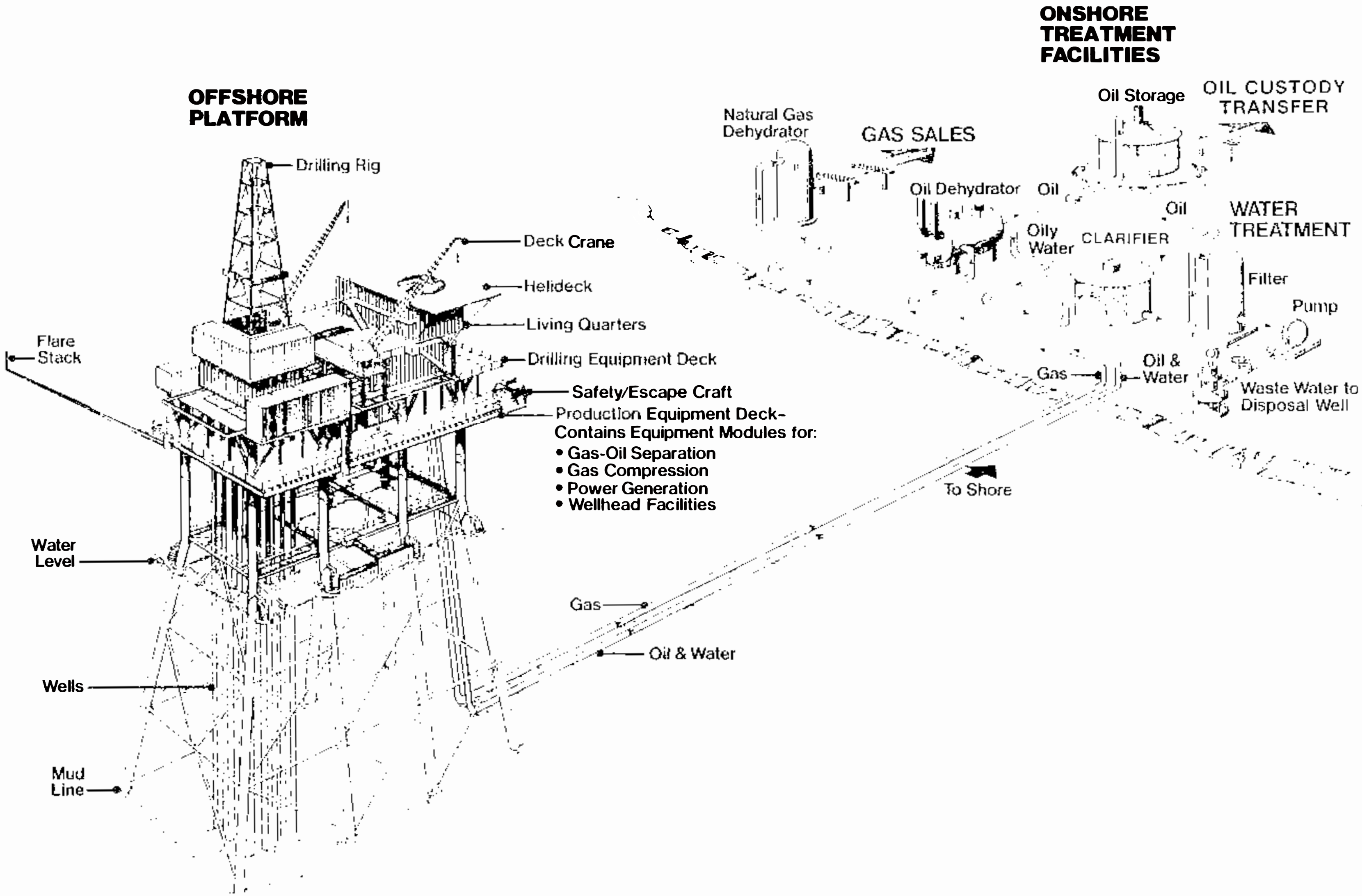


Figure 18. Offshore Oil Field Production Facilities and Development Drilling Rig.

SOURCE: National Petroleum Council, *Materials and Manpower Requirements for U.S. Oil and Gas Exploration and Production— 1979-1990*, December 1979.

considered feasible for future Bering Sea Arctic development in water depths of about 600 feet.

Artificial islands have been dredged up in shallow water off the California coast and in about 60-foot water depths in the Canadian Arctic Ocean. Temporary gravel islands have been created in shallow Beaufort Sea areas using onshore gravel.

Much research and development has been concentrated on the technology of deepwater (2,000 feet or more) development drilling and production operations. A promising concept is the tension leg steel tower, a platform provided with buoyant legs fixed to an ocean floor structure. The platform deck could translate horizontally but would be restrained from moving vertically. Another concept, the guyed tower, would be restrained horizontally by a conventional anchored guying system.

Ocean floor well completion systems and production facilities have been developed for deep water and pilot tested in shallow Gulf of Mexico waters. Both unmanned systems, manipulated from the surface, and systems manned in atmospheric pressure chambers have been demonstrated. Such systems will be used when large oil or gas fields are discovered in water depths either technically or economically too deep for fixed structures. Subsea well completions are in use throughout the world to expand field development past the horizontal limit that can be reached by directional drilling from a fixed platform, thus minimizing the number of platforms required.

1. Rigs and Drilling Platforms

Offshore development drilling rigs are no different from land rigs except for being packaged in modules of convenient weight and size for a platform crane lift. Derricks are usually the old style square construction rather than the portable jack-knife type used onshore. The typical offshore platform rig has diesel prime movers driving electric generators, and all machinery is electric motor driven. Some land rigs are diesel electric drive but most are diesel mechanical.

Because of the high cost of an offshore platform and the advanced art of controlled directional drilling, several wells are usually drilled from each platform. While the well spacing on the platform is on about eight-foot centers, they may be hundreds of feet apart at producing depth to conform with well spacing regulations.

Platforms are usually built with well slot arrays in multiples of 12, depending upon the reservoir depth and whether there are multiple reservoirs to be developed. The slant of directionally drilled wells is limited by the ability of electric logging tools to slide down the hole. With usual drilling fluids, the limit is 55 to 60 degrees from vertical in 10,000- to 12,000-foot wells. Deeper wells (15,000-16,000 feet) are limited to about 45 degrees.

2. Accommodations and Logistics

Crew living quarters, mess, and recreation facilities are provided offshore. Supplies are delivered by service vessels provided with open decks long enough for double lengths of 40-foot casing, fresh water and diesel fuel cargo tanks, transfer pumps, and bulk tanks for dry cement and drilling fluid additives. Personnel are usually transported by helicopter.

IV. Formation Evaluation

During drilling many logging techniques are used to determine the presence of recoverable hydrocarbons and the depths of zones of interest. Mud logging continuously monitors the drilling fluid stream as it discharges from the well annulus for the presence of oil or gas, and for changes in drilling fluid properties. Drill cuttings are recovered for paleontologists to identify formations.

The bit rate of penetration log with constant weight on bottom and rotary speed indicates formation changes that can be correlated with the depth of similar formations encountered in other wells. Cores recovered from zones of interest can show the formation fluid content (oil, gas, and formation water). Laboratory examination can reveal the geological age, porosity (percent pore space), and permeability (ability to pass oil, gas, and water).

Electric logging is the most universally used formation evaluation technique. The logging tool is a sensitive instrument lowered down the hole on an insulated conductor cable (wire line). Electrical resistivity, natural electrical potential, natural radioactivity, induced radioactivity, induced sonic energy, and electromagnetic propagation are detected in the uncased hole at measured depths and recorded at the surface. Radioactive and temperature logs are used to evaluate the formation in cased holes and to locate cement behind the casing.

The wire line log physical measurements are used to correlate formation depth with other wells and to estimate the properties of the rocks traversed and the fluids contained in the rock pores. Logs recorded in drilling wells are the basis for most decisions to set production casing and develop the field. As a field is produced, the reservoir engineer uses the electric logs to estimate the reservoir boundaries and probable producing characteristics.

During drilling or completion, drill stem tests may be conducted to determine fluid content of the formation without making a well completion. A tool with a bottom valve is run on drill pipe and placed adjacent to the zone of interest. Packers are set to seal between the drill pipe and the wall of the hole. The bottom hole valve is then opened to allow formation fluid to enter the drill pipe. The fluid may be allowed to flow to the surface, or the valve may be closed after filling the drill pipe a few hundred feet. Drill stem tests can be run in the open hole or through casing perforations.

V. Completion Operations

A. Wellheads

During drilling operations, wellhead sections are installed after each casing string is set. A wellhead (casing head) is a heavy flanged steel connector which is threaded or welded to the casing top. Succeeding sections are connected by bolts and each has a valved outlet. The wellhead seals each casing annulus; each section supports the weight of the casing string run through it, and supports and seals it to the BOP until drilling is completed and the well perforated.

B. Perforation

The production casing and surrounding cement are perforated to provide a passage for oil and gas from the formation into the well bore. Before perforating, the casing is filled with drilling fluid or salt water of sufficient weight to prevent the well from flowing while the perforating tool is in the hole. The perforating tool is then run down the casing on an electric conductor cable to a measured depth, predetermined during formation evaluation. Perforation is accomplished by successively firing shaped explosive charges, actuated from the surface.

C. Tubing, Packers, Safety Valves, Christmas Tree

Following perforation, tubing is run to provide a conduit for fluid flow to the surface and to protect the production casing from internal pressure and corrosion. Tubing is sized for rate and type of production anticipated and for convenient passage through the casing. The outside diameter is usually 2-7/8 inches for 7 inch casing and 2-3/8 inches for 5-1/2 inch casing. The tubing is hung from a tubing head, flanged and sealed to the casing head, with the bottom positioned above the casing perforation. In deep or high-pressure wells, a packer is attached to the bottom of the tubing and set to seal the annulus so that a fluid can be left between tubing and casing for pressure and corrosion protection.

Most wells are completed through a single string of tubing to produce from a single reservoir. If more than one productive zone is penetrated by a well bore, and it is desirable to produce them simultaneously, multiple completions can be made. Two or three parallel strings of tubing, isolated by packers and attached to a multiple christmas tree, can be installed for individual zone control. The disadvantages of multiple completions are the complicated mechanics of packer settings and smaller diameter tubing strings, which can limit flow rates.

A subsurface safety valve landing nipple is run in the tubing string of wells completed in marine, urban, or environmentally sensitive areas to provide downhole emergency shutoff to prevent uncontrolled flow should a failure occur in surface control equipment.

The final equipment installed on a producing well is the christmas tree. It is a manifold of valves and fittings flanged and sealed on the tubing head to provide flow control from the tubing to a gathering line, which carries production to processing and storage facilities. A small orifice (choke), a needle valve (adjustable choke), or a power operated automatic valve regulates the flow. Figure 19 shows a high-pressure christmas tree.

D. Stimulation

If a well does not flow, a plug-like device called a swab is lowered through the christmas tree and down the tubing on a wire line. When the swab is pulled up the tubing, removing part of the fluid, the resulting bottom hole pressure differential will cause formation fluids to flow into the borehole. If swabbing does not result in expected flow rates, other stimulation techniques may be tried.

Some producing formations are sensitive to drilling fluids, which seep in and swell minute clay particles, forming a block. This block may be removed by injecting a small volume of a surface active agent (surfactant). Limestone formations can usually be stimulated to higher production rates by injecting several thousand gallons of hydrochloric acid with some hydrofluoric acid added to dissolve mud cake.

The most widely used stimulation process is formation fracturing. Large volumes (several thousand gallons) of a viscous fluid containing coarse sand, glass beads, or other particulate matter in suspension is pumped down the tubing or casing and into the formation at a high rate and pressure. This creates fractures in the formation that may extend several hundred feet from the well bore, and are propped open by the particulate matter. Successful fracturing treatment can greatly increase the production rate and life of a well. Tight gas sands are particularly susceptible to fracturing.

Following stimulation, the tubing and packer are rerun, the christmas tree installed, and the well swabbed in under flowing conditions, or placed on artificial lift. The spent chemicals returning with produced fluids are recovered for disposal.

PRODUCTION

Production operations begin as the hydrocarbon reservoirs developed by completed wells produce oil, gas, and formation water mixtures through the lifting, gathering, and separation facilities. Disposition of the liquid products is by custody transfer. Natural gas is either injected or sold through a pipeline, and produced water (usually saline) is either discharged or injected underground. Typical onshore oil field production facilities are shown schematically in Figure 20 and simplified offshore facilities with onshore treatment facilities in Figure 18.

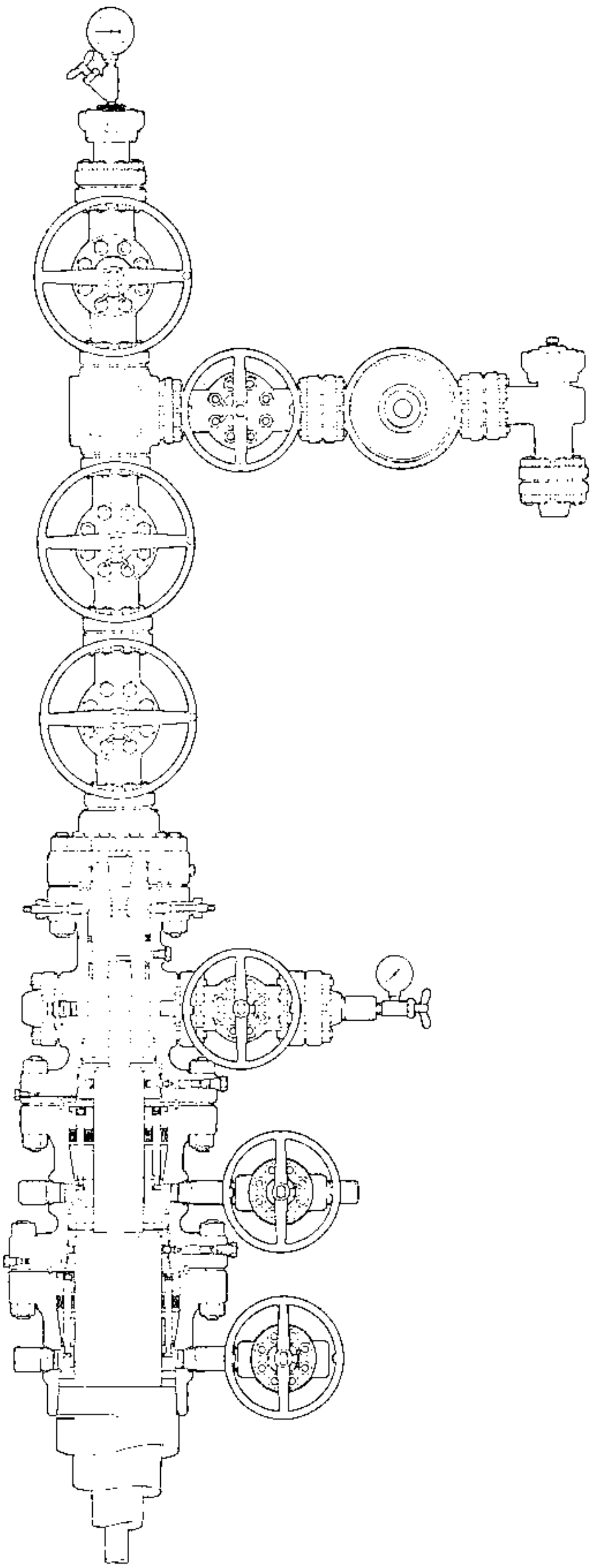


Figure 19. High-Pressure Christmas Tree.

SOURCE: Cameron Iron Works, Inc.

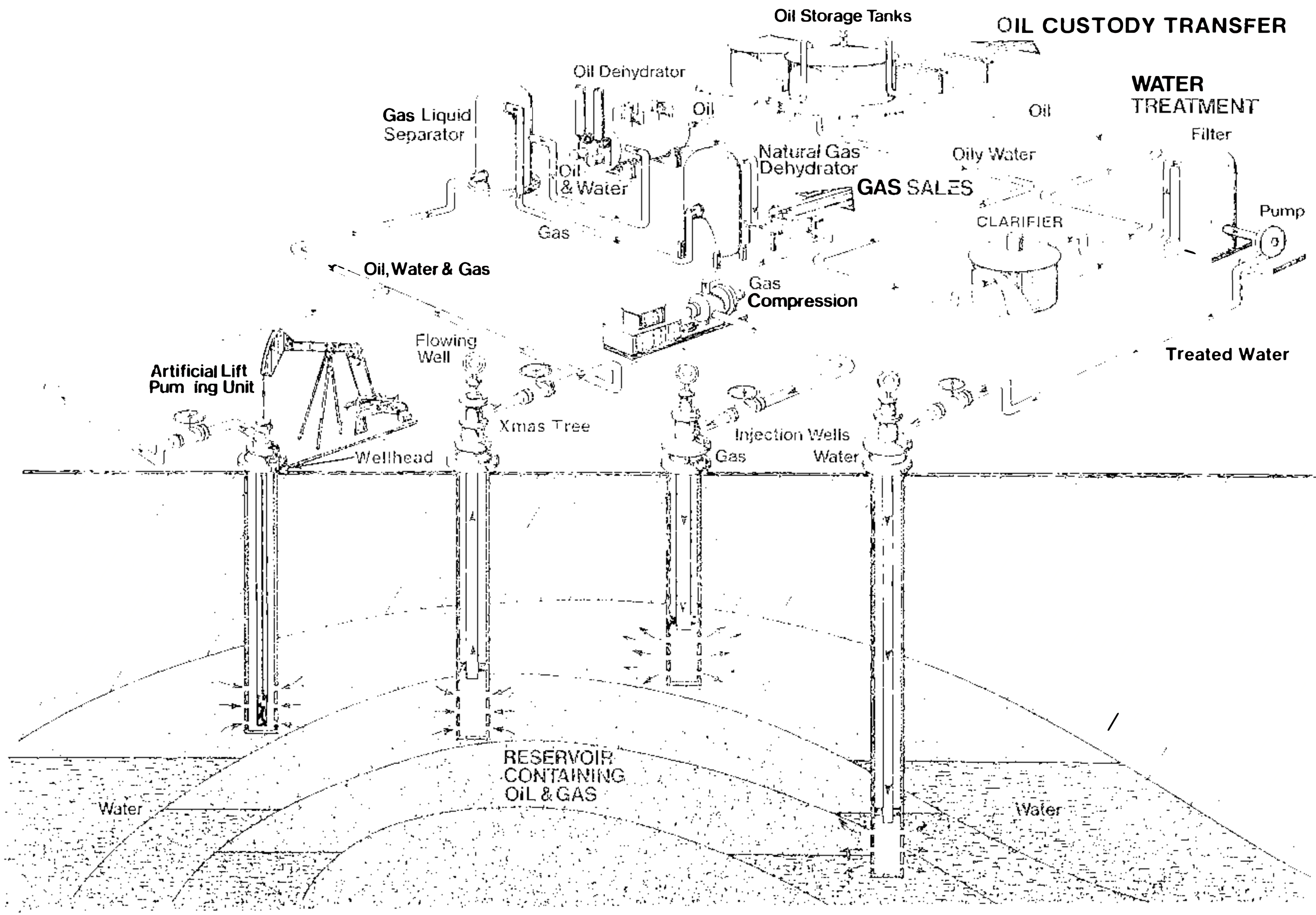


Figure 20. Typical Onshore Oil Field Production Facilities.

SOURCE: National Petroleum Council, *Materials and Manpower Requirements for U.S. Oil and Gas Exploration and Production—1979-1990,* December 1979.

I. Production Systems

The commingled oil, water, and gas flow from christmas trees through gathering lines to gas/liquid separators. These are pressure vessels with baffles and a quiet chamber where free gas separates by gravity and flows from the top of the vessel. The oil and water mixture moves from the separator to another separation vessel where, with the addition of heat and/or chemicals, oil/water emulsions are broken and the components separated by gravity aided by baffles and, in some units, by electrostatic action.

Oil then moves from the dehydrators to storage tanks for measurement or through meters to the custody of the pipeline company. Oil is sold by the producer to a refiner or broker. The pipeline operators, truckers, or barge operators serve as common carrier transporters.

Gas leaving the gas/liquid separator passes through a glycol dehydrator or a dry desiccant tower to prevent the formation of hydrates (solid water/gas mixtures), which can occur in high-pressure gas at low temperatures. The dry gas may then be metered to a pipeline for sale or compressed and injected into a producing formation for pressure maintenance.

Formation water passes through a clarifier to remove minute drops of oil. Onshore, the clarifier may be a large tank or a shallow pond. Retention time necessary to remove oil to an acceptable level varies with the gravity of the oil and the temperature. If a shallow holding pond is kept skimmed and the retention time is 24 hours or more, the average oil content of water discharged can be less than 25 parts per million (ppm). EPA regulations prohibit discharges in excess of 48 ppm on the OCS.

When the clean water leaves the clarifier, it may be discharged to tidewaters or injected through a disposal well into a nonproductive zone or into a producing zone for pressure maintenance and secondary recovery. Filtering may be necessary to prevent formation plugging. For safety and spill containment, dikes usually can hold more than the total capacity of the oil tanks.

A. Offshore Production Systems

Because of space limitations, offshore production facilities must be compact and set close together. An offshore installation, illustrated in Figure 18, separates the gas from liquids offshore, pumps the oil/water mixture onshore for separation, and compresses the gas for delivery to the onshore gas dehydrator.

If custody transfer to a pipeline company occurs at the offshore platform, the oil usually must be of salable quality, so oil/water separation equipment must be installed there. The produced water is cleaned by a mechanical clarifier and discharged into the sea when it meets regulated specifications.

To cope with the added safety hazards and greater potential for environmental pollution, safety devices are used offshore that are not necessary in usual onshore operations. Most are considered good practice by prudent operators but often they are required by regulations. The major safety devices on surface facilities are:

- Remotely operable, fail closed valves on each production well.
- Manual remote controls for emergency shutdown at a command center and at evacuation points. (The entire platform can be shut down from these controls.)
- High-low liquid level sensors on gas/liquid separators.
- High-low pressure sensors on all pressure vessels.
- High-low pressure sensors on all flowlines between the well choke and the valve manifold, which directs flow to gas/liquid separators.
- High-low liquid level sensors and high-low pressure sensors at appropriate locations on gas compressor installation.
- High-low pressure sensors and automatic and remotely operable valves on all oil and gas pipelines entering a platform from a satellite platform or leaving the platform.
- High-low pressure sensors on all pipeline pumps.

These malfunction sensors are connected to alarms. Appropriate sensors are designed to automatically shut in particular wells or the whole platform.

Wells that produce quantities of formation sand that can erode pipe and connections may be monitored by an erosion detector placed in the flowline downstream from the well choke. Erosion of the detector can close the well's automatic valve.

All oil or gas wells, including injection wells if capable of flowing, are equipped with a subsurface safety valve set in the well tubing 100 or more feet below the ocean floor. These valves are designed to stop flow automatically in case of accidental high rate of flow occurring at the surface. All subsurface safety valves with less than 4,000 psi surface pressure installed in U.S. OCS wells since December 1, 1972, are surface controlled. Subsurface controlled (velocity or pressure activated) safety valves are used in higher pressure wells.

B. Offshore Emissions and Effluents

Air emissions from a manned offshore production platform include those emitted from an offshore drilling rig: diesel engine exhaust, and products of combustion of diesel oil and natural gas burned in water heaters and space heaters for crew quarters. In

addition, there may be brief burning of natural gas in a flare during a well test. If the well being tested is exploratory and there are no facilities for saving the oil, an oil and gas mixture might be burned in a smokeless burner. Discharges to the sea from offshore production platforms are discussed in the Environmental Considerations section of this chapter.

First stage separation of oil and produced water offshore is usually by gravity under pressure in the "free water knockout" section of a gas/oil separator or in a separate pressure vessel downstream from the gas/oil separator. Retention time in the pressure vessel is quite short. Typically, the water leaving the first stage will contain from 100 to 300 ppm entrained oil, which must be clarified before it is discharged into the sea.

Several types of devices designed to remove finely divided oil droplets are commercially available, but few have proven practical in field tests. All systems work on the principle of accelerating the coalescence of the oil droplets, causing the oil to rise through the water column more rapidly so it can be skimmed. Types that have been extensively tested offshore include:

- Fibrous element coalescing devices, which are efficient when first installed but rapidly become plugged with fine particles of silt or paraffin present in the water.

- Centrifuges, which tests show to be efficient but were discarded because retention of solids caused high maintenance costs and significant power requirements.

- Upflow sand filters, which provide efficient separation but are limited in use because of the large platform space requirements, the close attention required, and the need to treat backwash water and solids.

- Gas flotation devices, which are used extensively in the Gulf of Mexico with good results. Coalescence occurs by mixing natural gas or air with the water. Rising bubbles bring oil droplets to the surface for skimming. Power is necessary to operate flotation cells, which require constant maintenance to keep up performance.

- Corrugated plate interceptors, which consist of a bundle of corrugated fiberglass plates spaced closely together and sloped. Produced water is directed through the bundle and between the plates. Accelerated coalescence is achieved by shortening the distance that oil droplets have to rise to contact a surface from several feet to a few inches. The coalescing oil droplets move along the fiberglass plates into a quiet chamber where they continue to rise to be skimmed and recovered. Corrugated plate interceptors are widely used because they give results comparable to multi-cell flotation units and require no power to operate other than a pump to move the water.

EPA statistical analysis of data from water clarifiers at Gulf of Mexico installations has shown that properly maintained gas flotation units maintain long-term effluent averages of about 25 ppm oil. The only alternatives to discharging produced water at sea after reducing oil content through state-of-the-art clarifiers are disposal in injection wells or transportation to shore for permitted disposal.

II. Artificial Lift

As reservoir energy diminishes and wells stop flowing, artificial lift systems are required to maintain production. The most common system is the artificial lift pumping unit illustrated in Figure 20. The pumping unit is powered by an electric motor or internal combustion gas engine. Steel rods (sucker rods) suspended from the oscillating beam head reciprocate a plunger pump in the tubing, located below the fluid level in the well.

Where sufficient gas is available, gas lift may be used. Gas forced into the tubing-casing annulus is injected into the tubing through gas lift valves below the fluid level of the well. Gas mixing with the fluid lightens the total weight of the fluid column to less than the reservoir pressure so that the well can flow to the surface.

Other, less common artificial lift systems are hydraulic-powered downhole plunger pumps and submerged electric motor-powered centrifugal pumps. The most widely used artificial lift systems offshore are gas lift and hydraulic pumps. Walking-beam pumps are generally too bulky for offshore use. Submerged centrifugal pumps are applicable to very large volume rates, usually where salt water content is over 70-75 percent.

III. Production Maintenance

Many operations are performed on wells to maintain production rates, extend productive life, and increase total hydrocarbon recovery. Most operations need a well servicing rig and specialized services such as well stimulation, most of which are furnished by contractors. The typical production well servicing rig has a self-propelled carrier, drawworks, a swabline, and a mast that can be raised with rig power and extended above the wellhead.

A. Artificial Lift Servicing

A well servicing rig is used to pull sucker rods to repair the downhole pump or replace broken rods, which occur many times in the life of a pumping well. During these jobs, paraffin deposited from the oil may be scraped from tubing walls or sand bailed from the well. Occasionally, worn sections of tubing may be replaced. Gas lift, hydraulic pumps, and submersible electric well pumps are also pulled for repairs.

B. Workovers

Most oil and gas wells require downhole servicing called workovers after completion. It is usually necessary to confine well

pressure by filling the well with a weighted fluid and then pulling the tubing with a well servicing rig.

Common workover jobs include reducing salt water or excessive gas production from an oil well. Tubing or drill pipe is run in the hole with a packer that is set to seal the casing annulus above the perforations. Cement is then pumped down the tubing and squeezed through the perforations. The packer is unseated and excess cement washed out. After the cement has set, the well is re-perforated higher or lower in the well (as indicated by examination of well logs) and the well is recompleted. Workovers may also use stimulation procedures such as those described in the previous section.

C. Sand Control

Some oil and gas reservoirs are composed of unconsolidated sandstones, which move with the produced oil and gas into the well bore. This can erode valves and pipe fittings at the surface and eventually stop flow by accumulation inside the casing. A Monel metal wire screen wrapped around perforated pipe and set adjacent to the producing formation used to be a common remedy. Gravel pack and plastic consolidation are more effective modern methods.

For a gravel pack, a screened perforated pipe is run with a packer above and set adjacent to the perforations. Graded coarse sand (gravel) is pumped down the tubing, the annulus between the screen and perforations is filled and some of the gravel is pumped into the formation.

For a plastic consolidation, a liquid prepolymer is pumped through the perforations, followed by a catalyst that causes the plastic to solidify on the sand grains, cementing them together without plugging the interstitial space. Plastic consolidation reduces permeability, thus lowering producing rates.

D. Corrosion Control

Most of the corrosion onshore occurs on buried pipelines and downhole well equipment. External corrosion of buried pipelines is controlled by a heavy asphaltic wrapping or a tough extruded plastic coat. Large pipeline gathering systems may also be protected cathodically by imposing electric current. Internal corrosion of flowlines (well to gas/oil separation) can be reduced by injecting corrosion inhibiting chemicals at the well.

Corrosion of downhole rod pumping equipment can be very costly. Corrosion-resistant materials are used in pump parts and, if corrosion is severe, corrosion inhibitors are injected into the well.

Gas wells may produce CO_2, which becomes corrosive when dissolved in produced water. A corrosion inhibitor can be batch injected into gas well tubing to reduce this type of corrosion. Many high-pressure gas wells and certain crude oil wells produce

some H_2S, which can cause hydrogen embrittlement cracking in very hard, high tensile steels. Special alloy steel pipe, valves, and fittings are used under these conditions.

Offshore platforms require special corrosion protection from continuous exposure to salt water for many years. There are three areas of exposure requiring differing protection:

- Atmospheric Zone -- This zone has the lowest corrosion rate but is the most expensive to maintain. Many types of coatings have been tried, leading to the use of high-quality, heavy-bodied coatings. During construction, platforms are sand blasted to white metal before coating. An effective combination is an epoxy mastic over inorganic zinc. Additional repainting is required at the conclusion of development drilling and subsequently at five- to eight-year intervals.

- Splash Zone -- This zone is kept wet by wave action and is above the area that can be cathodically protected. Noncorrosive coverings applied to the splash zone include wrought iron, fiberglass, stainless steel, and Monel. Modern platform designs aim at minimizing the platform area in the splash zone.

- Immersed Zone -- Although the bulk of a platform in deep water is immersed, this part is the simplest to protect. Cathodic protection is provided by sacrificial galvanic anodes or impressed current systems, which use generator-rectifier units and special anodes to resist deterioration.

E. Primary Recovery

Oil reservoirs are not caverns or immense underground pools. Accumulations of oil occur in the pore space between grains in sandstone or in the very fine pores and fractures in limestone. Petroleum source beds are usually the nearby shale formations from which the oil and gas migrated upward into the porous rock where it was trapped by a less permeable barrier.

The volume of oil in a reservoir that can be produced by primary methods (flowing and artificial lift) varies greatly with many factors. The most important are:

- Permeability (ability to pass fluid)

- Porosity (percent pore space)

- Viscosity (thickness) of the oil

- Reservoir energy (fluid expansion, gas cap, or underlying water reservoir).

Oil clings to sand grains by surface tension, which increases with oil viscosity and smaller grain size. Also, as water invades

an oil zone or gas bubbles accumulate in the pore space, the rock pores become less permeable to oil; i.e., the oil tends to stay in the pore space and not move into the well bore. The whole technology of oil recovery has the objective of moving as much oil as is economically possible into the well, where it can flow or be pumped to the surface.

Reservoir oil contains some dissolved gas. As oil is produced, reservoir pressure is reduced by fluid expansion, allowing part of the gas to come out of solution in the formation, thus increasing oil viscosity and impeding flow.

Reservoirs containing only oil (fluid expansion drive) rapidly decrease in productivity as reservoir pressure declines, causing very low primary recovery. Reservoirs with associated gas caps have longer flowing lives and higher primary recovery volumes, but higher gas-to-oil producing ratios. Water drive fields are underlain with formation water in contiguous permeable rock. The natural water drive comes from the expansion of reservoir water volumes much larger than the oil reservoir, resulting in the highest oil recovery of the three primary mechanisms. As water invades the oil zone, large volumes are produced with the oil, usually requiring artificial lift and always causing a water disposal problem.

F. Pressure Maintenance and Secondary Recovery

To lengthen the flowing life of oil wells and to increase recovery, pressure maintenance may be started early in the life of a field. Gas produced with the oil and not used for surface operations is injected into the producing formation, usually at the crest, to maintain pressure and gravitational segregation. After treatment, seawater, produced water, or water from source wells may be injected below the oil zone.

Many oil fields that were produced to pressure depletion became economically marginal. They have been restored to production and recoverable reserves substantially increased by secondary recovery methods.

The earliest secondary method was repressuring with extraneous natural gas, transported from a nearby gas field. Due to the present value of gas, some gas injection projects for pressure maintenance and secondary recovery use part of the gas in internal combustion engine driven compressors and inject the exhaust (inert gas) into the reservoir.

The most widely used secondary recovery method is water flooding. A grid pattern of wells is established, which usually requires downhole repairing of old wells and drilling of new wells. By injecting water into the reservoir at high rates, a front or wall of water moves horizontally from the injection wells toward the producing wells, building up the reservoir pressure and sweeping oil in a flood pattern. Water flooding has substantially improved oil recovery from reservoirs that had little or no remaining reservoir pressure.

G. Enhanced Oil Recovery

Enhanced oil recovery (EOR) is also called "tertiary recovery" when it follows a secondary recovery program. In a broader sense, EOR may be referred to as any method following primary depletion. After primary and secondary economic depletion, oil reservoirs still contain significant volumes of oil. The 1976 National Petroleum Council (NPC) report, Enhanced Oil Recovery, states:

> While recovery in individual reservoirs is highly variable, the average recovery from conventional primary and secondary recovery methods in all U.S. reservoirs is expected to be only about one-third of the original oil in place, leaving nearly 300 billion barrels in currently known reservoirs. A portion of this remaining oil is a target for enhanced oil recovery. The rest exists in unfavorable geological or geographic regions or is so diffusely spread out in the reservoir rock that it very likely will not be recoverable by any process.

There are three general classifications of EOR: thermal, CO_2 miscible flooding, and chemical flooding. Of these, only one of the thermal methods (steam flooding) has had several large-scale commercial applications. Thermal processes add heat to the reservoir to reduce oil viscosity or to partially vaporize the oil so that it can be more easily driven to producing wells.

Steam injection has been applied for several years in California heavy oil reservoirs, usually in two separate steps: steam stimulation of producing wells, and then steam drive from injection wells to nearby producing wells. During the first stage, called "huff and puff," or "steam soak," steam and hot water are injected into a producing well for several days or weeks. The well is shut in for several days, and then produced for several weeks or months. The injected heat lowers the viscosity of the oil while the hot water flashes to steam, providing driving energy. "Huff and puff" may be followed by a steam drive.

In situ (within the reservoir) combustion has also been extensively field tested. Heat is generated in the reservoir by injecting air and burning part of the crude oil in the formation. This reduces the viscosity, partially vaporizes the oil in place, and drives it forward by a combination of steam, hot water, and gas drive. Production is from wells near injection locations. In some applications, water and air injections are alternated. The injected water can improve utilization of heat by moving it forward from the rock immediately behind the combustion zone.

There are several CO_2 displacement projects in various stages of operation. CO_2 is capable of miscibly displacing some oils, thus permitting recovery of most of the oil from the reservoir rock that is contacted. Miscible displacement (complete solubility of fluids) overcomes the capillary forces (surface tension) that otherwise retain oil in pores of the rock. The CO_2 is not initially miscible with the oil, but as the two contact each other at

increasingly higher pressures some of the hydrocarbons of the crude oil are vaporized. At the displacement front, the resulting mixture becomes miscible with both the CO_2 and the in situ oil.

Large volumes of CO_2 are required for this process. During later stages, water or inert gas may be injected behind the CO_2 to maintain pressure and provide displacement energy. Increasing amounts of CO_2 will be produced with the oil and must be separated for reinjection or disposal.

Chemical flooding is the most complex and has the highest degree of commercial and technological uncertainty of the EOR processes, yet may have the greatest potential for maximum recovery. Various systems have been extensively pilot tested and there are several full-size field applications underway. The three general types of chemical floods are: surfactant (surface tension reducing agent), polymer (organic chemical), and alkaline.

Surfactant flooding is a multiple slug process, involving the addition of surfactants to a water volume representing only a small fraction of the total reservoir volume. When this small "slug" is injected it lowers the interfacial tension between the oil and water, thereby improving displacement efficiency. The surfactant is followed by a larger slug of water containing a high-molecular-weight polymer to improve sweep efficiency and preserve the integrity of the costly slug of surfactant chemicals. Surfactant systems must be designed for the unique fluid and rock properties of the specific reservoir and are pilot tested to evaluate effectiveness.

Polymer injection augments water flooding. Polymers used are synthetic (polyacrylamides) and biologically produced (polysaccharides). These high-molecular-weight polymers are added to thicken injected water, decreasing its mobility, increasing sweep efficiency, and thus increasing recovery. The process may be used with higher viscosity oils than are feasible for the surfactant process, but the potential additional recovery above conventional water flood may be modest. Polymer flooding is being used commercially on a limited scale.

Alkaline flooding adds chemicals such as sodium hydroxide, sodium silicate, and sodium carbonate to flood water to enhance recovery by interfacial tension reduction, spontaneous emulsification, or wetability alteration. These mechanisms occur when surfactants are formed from the neutralization of petroleum acids by the alkaline chemicals. Alkaline flooding is applicable primarily to recovery of moderately viscous, low API gravity, naphthenic type crude oils, which normally contain enough natural petroleum acids for the process. Alkaline flooding has had less field testing than the surfactant and polymer systems.

H. Abandonment

When production operations are permanently abandoned, surface equipment and materials are removed or left in place in accordance

with surface owners' agreements and regulatory requirements. Surface owners may request that improvements such as roads and water wells be left intact. Small buried pipelines (well flowlines) may be salvaged or left in the ground. The degree of surface restoration will vary with the location. When a fixed platform offshore is abandoned, all piling and well casing is removed to a depth of 15 feet below the ocean floor and the area dragged to clear the site of obstructions. All wells permanently abandoned are left in a condition to prevent communication between any water- and hydrocarbon-bearing zones penetrated by the well bore.

If a well has been produced, the tubing is pulled and salvaged. Production perforations or open hole are covered with a cement plug extending up into the casing. The wellhead is salvaged and the production casing and the intermediate casing strings may be cut above the annular cement and salvaged. If the casing strings are pulled, cement plugs are set to overlap the cut casing top, leaving cement to extend above and below the cuts. If more than one casing string extends to the surface (surface casing and conductor casing), cement is pumped down the annulus between the two strings. The last cement plug is set in the smallest casing string that extends to the surface and is placed with the cement top near the surface.

The length of each cement plug set in an abandoned well will vary with the well and applicable regulatory requirements. After each plug is placed, drilling fluid is circulated above the plug and weighted such as to overbalance formation pressure behind the casing at that point.

The final step in abandonment is to cut off the surface and conductor casing at an appropriate depth below the surface. On land locations, this is usually below plow depth in farming areas or six feet in urban areas, in accordance with applicable regulations. After cutoff on land, a plate is usually welded on top of the casing for a seal and a small high-pressure valve installed for later determination if gas pressure has accumulated. The hole above the well is then filled and tamped.

If a reserve pit was used to store well cuttings and excess drilling fluid, the clean water may be drained off or the drilling fluid pumped into the surface casing annulus if allowed by applicable regulations. After the remaining mud and cuttings are dried, the reserve pit dikes are leveled, and the mud is scattered and plowed under, or moved to an approved disposal site. Mud and cuttings disposal is discussed in the Environmental Considerations section of this chapter. Usable drilling fluid is valuable and is usually moved by tank truck to another drilling site or to an approved storage site.

NATURAL GAS PROCESSING

Economically recoverable natural gas occurs in petroleum reservoirs either dissolved in the crude oil, as a gas cap above

the oil, or as a gas trapped in a reservoir not associated with oil. The raw gas from these three sources can be gathered for processing to extract products to be marketed as liquefied petroleum gas (LPG) and natural gasoline as shown in Figure 21.

When petroleum reaches the surface and discharges into a gas/oil separator at reduced pressure, most of the gas dissolved in the oil will be released. When gas well production expands into a gas/oil separator, part of the heavy hydrocarbons that may have been in the gas phase in the reservoir will condense and separate as a liquid, called condensate.

All formation gas contains some water in solution. When pressure is partially released at the surface, causing a rapid drop in temperature, the entrained water can combine with the gas to form solid hydrates, which can plug a gathering line. Dehydration units are usually installed in the field to dry the gas sufficiently to prevent hydrate formation by low-temperature separation, glycol contact, or dry desiccant.

If the produced gas is sour (containing H_2S and/or CO_2), these contaminants must be removed before processing or marketing. This removal is usually accomplished by chemical absorption, with amine or potassium carbonate. The process is reversible, the chemicals being regenerated and re-used. The CO_2 residue can be discharged and the H_2S may be flared, forming sulfur dioxide (SO_2). If SO_2 flaring is not permissible, it can be converted to elemental sulfur for sale or disposal.

Natural gas contains a mixture of hydrocarbon molecules, identified by the number of carbon atoms in the molecule. The lightest is methane (C_1), with a gas specific gravity of 0.55, and the heaviest is decane (C_{10}), with a gas specific gravity of 4.91. However, hydrocarbons above the C_2-C_3 range comprise a very small percentage of "natural gas" even though hydrocarbons of greater than C_{10} can be found in isolated areas. Each has a different specific gravity and boiling point, which permits separation by fractional distillation. The percentage of each component in a raw gas stream may vary widely. Some produced gas does not have enough heavy components to justify separation.

There are approximately 770 gas processing plants in the United States, of which over 70 percent are in Texas, Louisiana, and Oklahoma. Commercial natural gas processing plants are designed to extract part of the ethane (C_2) and heavier components for sale as liquids, leaving the methane and part of the ethane for sale as gas. The gas sold usually has a heating value of approximately 1,000 British thermal units (Btu) per standard cubic foot, which is the historical base for gas contracts. The LPG recovered may be sold to a refinery as a feedstock or fractionated into commercial LPG products and natural gasoline. The flow of natural gas through processing is shown in the simplified diagram in Figure 21.

It is neither practical nor necessary to separate LPG exactly into the basic components. The products are sold subject to Natural Gas Processor Association standards and contract specification,

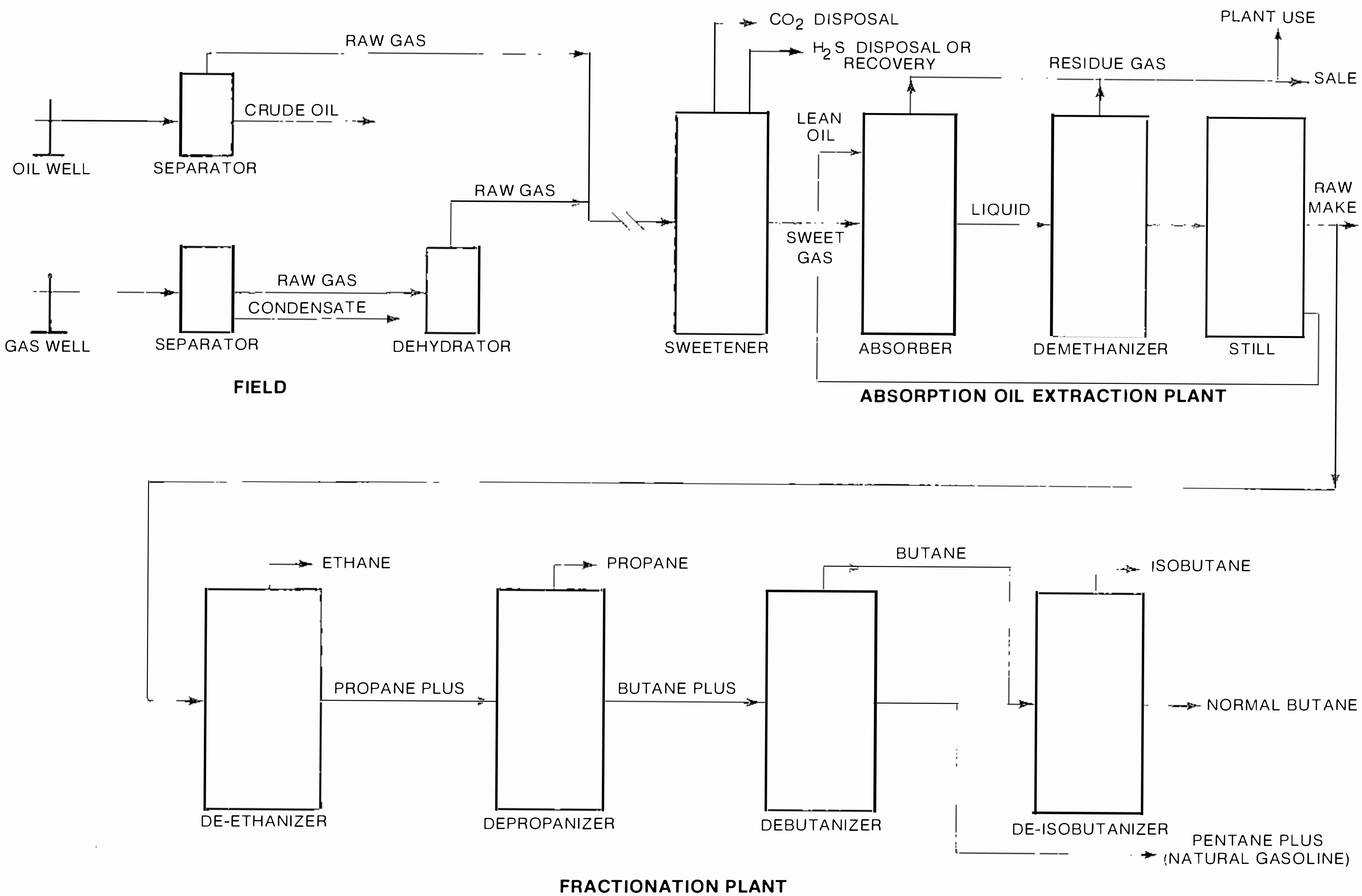


Figure 21. Natural Gas Processing Flow Diagram.

which allow for some tolerance in components. The usual products produced by a fractionating plant are:

Product	Atmospheric Pressure Boiling Point (°F)
Ethane	-128
Propane	- 44
Isobutane	11
Normal Butane	31
Pentane and Heavier	82-250

The pentane and heavier product with some butane is commonly called natural gasoline, which can be stored at atmospheric pressure in tanks.

Conventional gas processing plants extract LPG from the raw gas stream by absorption in a light refined oil or by cryogenic separation. The raw gas enters the bottom of a tower equipped with several levels of trays with bubble caps. While the gas passes upward and out the top of the tower, the lean absorber oil is pumped in the top, spilling from tray to tray where it intimately contacts the rising gas, absorbing all except the methane and part of the ethane and propane. Gas leaving the top is called residue gas and is ready for sale after dehydration.

Conventional absorption plants operating at 90° to 100°F recover up to 85 percent of the propane but very little ethane. When economically justifiable to reduce the lean oil temperature, about 15 percent of the ethane can be recovered at 0°F and 60 percent at -45°F. Modern turbo-expander plants operating as low as -130°F can recover 50 to 90 percent of the ethane.

The liquid drawn from the absorber is now a rich oil containing a small amount of methane, which must be removed before being carried over into the LPG products. The methane present in the distillate is removed by flashing the distillate back to gas, then condensing at a temperature that will not capture methane. This process is called demethanizing.

The product is now marketable as "raw make." If the plant markets the usual LPG products and natural gasoline, the raw make is passed through a series of fractionation towers, each successively removing a light component as shown on the next page.

These fractionation steps are identical except for variations in tower temperature gradient and temperature of the overhead condenser. Feedstock is injected into the side of a tower, which is maintained with a temperature gradient from hotter at the bottom to cooler at the top. Liquid drawn from the bottom of the tower is heated to above the boiling point of the product to be removed and the vapor injected back into the tower where it rises and goes out the top. The leaving vapor goes through a condenser, which cools it below the boiling point of the heavier components, which are pumped back into the tower near the top. The lighter fraction is

thus separated, condensed, and pumped to a pressure vessel for storage and sale for fuel or petrochemical feedstocks. The heavier bottom product passes to the next fractionator until the final residue is pentane and heavier (natural gasoline), which is a refinery feedstock.

Fractionator	Feedstock	Product: Top	Product: Bottom
De-ethanizer	Raw make or LPG	Ethane	Propane and heavier
Depropanizer	Raw make or de-ethanized propane and heavier	Propane	Butane and heavier
Debutanizer	Depropanized butane and heavier	Butane mix	Pentane and heavier (natural gasoline)
De-isobutanizer	Butane mix	Isobutane	Normal butane

The minimum area required (and spacing requirements) for gas processing facilities is dictated by safety requirements. These requirements are described in the Industrial Risk Insurer's 1978 publication, Recommended Guidelines for Gasoline Plants. A small gas field, where separators, dehydration, compression, and salt water disposal are required but gas processing is not justified, needs about seven acres for these facilities. A full scale processing plant for absorption and fractionation requires about 40 acres.

Air emissions from a natural gas processing plant are primarily products of combustion from heaters, internal combustion engines, and sulfur recovery processes. Plants are provided with flares for safely disposing of gas or liquid products during an operational upset when pressure vessels must be relieved suddenly. On these rare occasions, flares may burn with a visible flame.

Normal plant operation requires few water discharges. Some plants have water from cooling tower bottoms for disposal. If the full unseparated stream from gas wells flows to a plant, there may be produced water for disposal. Wastewater sources and disposal are discussed in the Environmental Considerations section of this chapter.

Normal plant operations generate a wide variety of solid wastes. Disposal may be by incineration, land fill burial, or commercial disposal.

The 1975 American Petroleum Institute (API) Division of Production publication, Recommended Gas Plant Good Operating

Practices for Protection of the Environment, is a composite of recommended industry onshore gas processing plant operating practices for protection of the environment. Plant processes and storage facility recommendations are described in the appendices to that publication.

U.S. RESOURCE BASE

The question of the amount of domestic oil and gas that remains to be produced can be a source of confusion and apparent contradiction. Many companies, private groups, and government agencies publish estimates of the remaining domestic petroleum resources, each attempting to accurately represent the nation's untapped petroleum resources. Each estimate may be valid, for each may be measuring different things. An estimate may attempt to answer a question as narrow as the extent of proven reserves, or as broad as the amount of original oil in place. While two such figures would vary significantly (probably by an order of magnitude), each would be valid in terms of what is being estimated.

A number of independent assessments of differing resource classifications, all considered components of the total U.S. resource base, are presented in this section. The NPC presents these estimates as indicative of the many objective and impartial estimates of the total U.S. resource base, but their inclusion does not denote NPC endorsement. Further discussion of the potential Alaskan reserves is found in the NPC s 1981 report, _U.S. Arctic Oil and Gas_.

CONVENTIONALLY PRODUCIBLE OIL AND GAS

In a 1981 report entitled _Estimates of Undiscovered Recoverable Resources of Conventionally Producible Oil and Gas in the United States, A Summary_, the USGS estimated undiscovered recoverable resources for 15 petroleum regions (11 onshore and four offshore) in the lower 48 states and Alaska (see Figure 22). Undiscovered recoverable resources, by USGS definition, can be extracted economically under existing technology and price/cost relationships -- that is, assuming normal, short-term technological growth.[1] These resources are indicated by the shaded area on Figure 23. The other classifications of petroleum resources not assessed in the USGS study include the following:

- Measured reserves: " ... that part of the identified resource which can be economically extracted using existing technology, and whose amount is estimated from geologic evidence supported directly by engineering measurements."

- Indicated reserves: " ... reserves that include additional recoveries from known reservoirs (in excess of measured reserves) which engineering knowledge and judgment indicate will be economically available by application of fluid injection whether or not such a program is currently installed."

  Inferred reserves: " ... reserves in addition to demonstrated reserves eventually to be added to known fields through extension, revisions, and new pays."

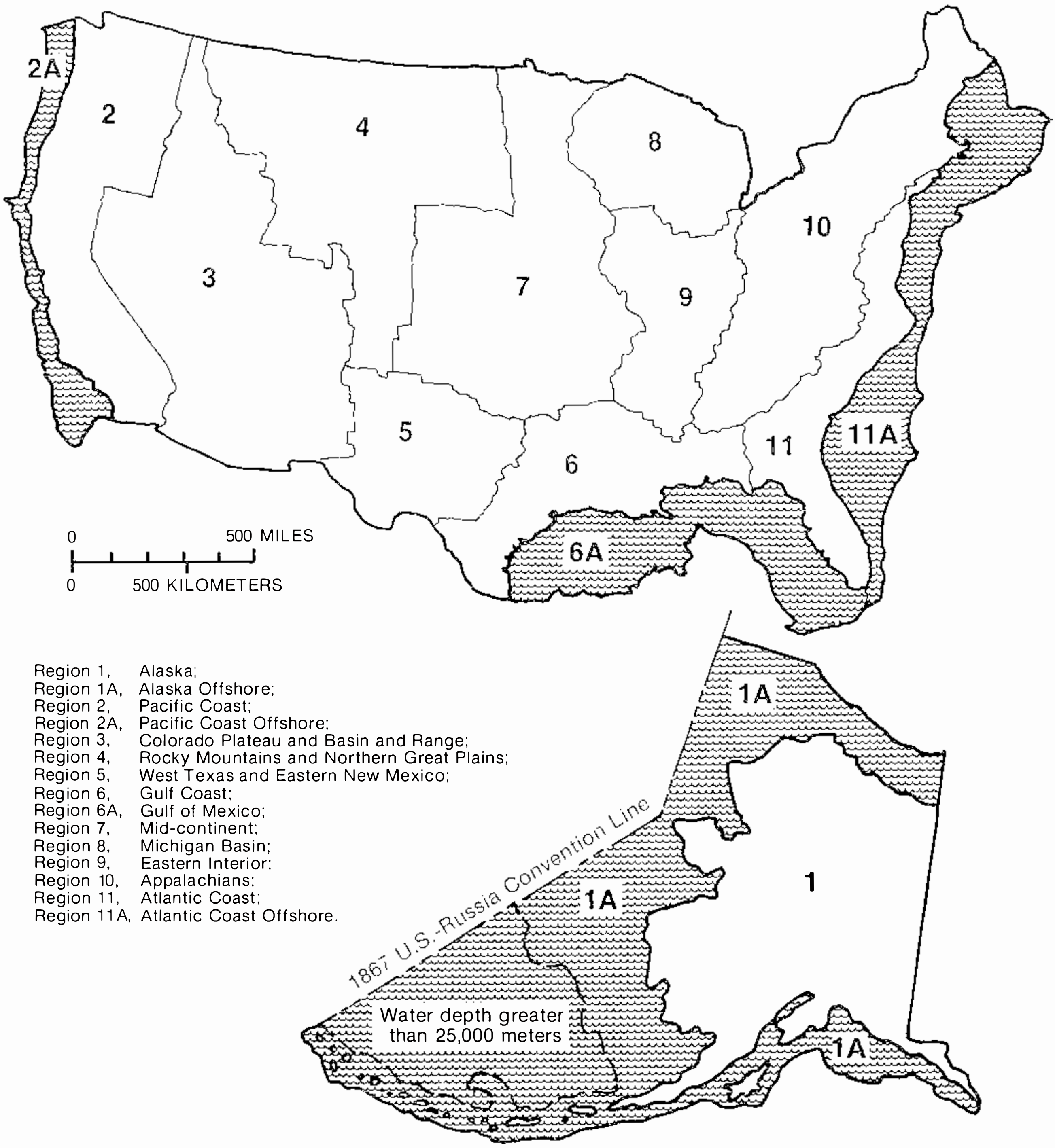


Figure 22. Maps Showing the Regional Boundaries Used by the U.S. Geological Survey.

NOTE: The United States has not resolved its offshore boundaries with other states concerned. The lines on this chart are for purposes of illustration only, and no not necessarily reflect the position or views of the United States with respect to the boundary involved.

SOURCE: U.S. Geological Survey, *Estimates of Undiscovered Recoverable Resources of Conventionally Producible Oil and Gas in the United States, A Summary*, February 1981.

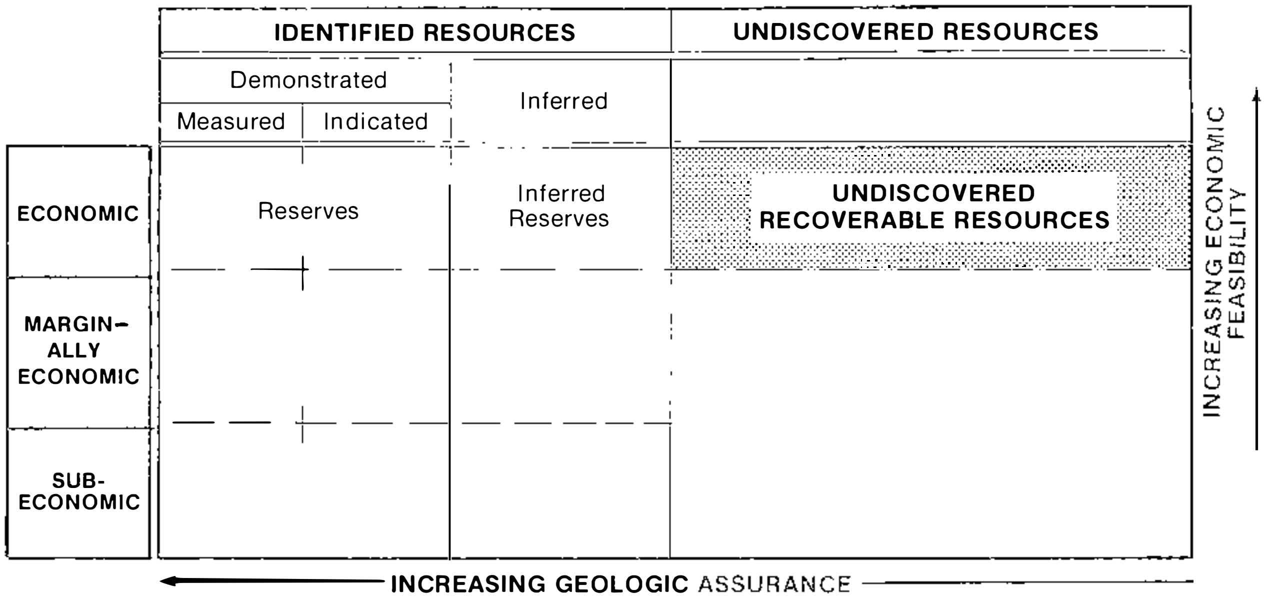


Figure 23. Petroleum Resource Classification (Modified from U.S. Bureau of Mines and U.S. Geological Survey, 1980).

SOURCE: U.S. Geological Survey, *Estimates of Undiscovered Recoverable Resources of Conventionally Producible Oil and Gas in the United States, A Summary*, February 1981.

- Identified sub-economic resources: " ... known resources that may become recoverable as a result of changes in technological or economic conditions."

- Sub-economic undiscovered resources: " ... quantities of a resource estimated to exist outside known fields on the basis of broad geologic knowledge and theory."

USGS defined crude oil as a mixture of hydrocarbons occurring in an underground reservoir in a liquid state and remaining in a liquid state as it is produced from wells. Natural gas was defined as a mixture of hydrocarbons occurring in an underground reservoir either in association with crude oil or as free gas dissolved in crude oil, or in a free state not associated with crude oil. Heavy oil deposits, tar sands, oil shale, tight gas sands, gas occluded in coal, gas in geopressured shales and brines, and natural gas hydrates were not included in the USGS assessment.

USGS subdivided the 15 petroleum regions into 137 provinces. Assessments of each province were based on a review of the province's petroleum geology, exploration history, volumetric-yield procedures, finding-rate studies, and structural analyses. Because of the uncertainties involved in estimating undiscovered resources, USGS used a range of values corresponding to different probability levels. Initial assessments were made as follows:

- A low resource estimate corresponding to a 95 percent probability of more than that amount; this estimate is the 95th fractile (F_{95}).

- A high resource estimate corresponding to a 5 percent probability of more than that amount; this estimate is the 5th fractile (F_5).

- A modal ("most likely") estimate of the quantity of resource associated with the greatest likelihood of occurrence.

The results of the USGS assessment demonstrated a range of conventionally producible undiscovered oil and gas resources for the United States. The 95 percent probabilities for crude oil and natural gas are 64.3 billion barrels and 474.6 trillion cubic feet (TCF), respectively, whereas the 5 percent probability values are 105.1 billion barrels and 739.3 TCF of gas (see Table 16). The USGS's most likely estimates indicate total onshore undiscovered recoverable resources of 54.6 billion barrels of crude oil and 426.9 TCF of natural gas, and a total offshore resource base of 28.0 billion barrels of crude oil and 167.0 TCF of natural gas. The mean total amount of oil appraised for the entire United States and its offshore areas changed very little from the 1975 USGS assessment, whereas the estimated total for natural gas has increased.

The NPC conducted an independent assessment of oil and gas resources for all areas in Alaska under U.S. jurisdiction north of the Aleutian Islands offshore, and north of the Brooks Range onshore. The NPC estimates the volume of undiscovered potentially recoverable hydrocarbons on the North Slope of Alaska to be 12.8 billion barrels of oil equivalent (BBOE), and from the Bering, Beaufort, and Chukchi regions offshore to be 30.8 BBOE. While these estimates are not strictly comparable [e.g., USGS excludes natural gas liquids (NGL) and in some instances USGS and the NPC considered different minimum field sizes], there is general agreement between the NPC and USGS on total Arctic potential. Details of the NPC's assessment are published in its 1981 report, U.S. Arctic Oil and Gas.

Besides those resources that are presently economical, undiscovered, and recoverable, there are other classifications of oil and gas. The marginally economic and sub-economic categories of undiscovered resources add a considerable amount to the estimates of the U.S. resource base. Tight gas reservoirs and enhanced oil processes are two examples of the latter classification and are discussed below.

TIGHT GAS RESERVOIR POTENTIAL

In 1980 the NPC completed an assessment of potential resources and recovery for tight gas reservoirs (Unconventional Gas Sources -- Volume V). The NPC appraised in detail 12 basins, which contained natural gas in either blanket or lenticular formations, with an in situ effective permeability of less than one millidarcy. Until recently, most of these formations have been uneconomical to produce due to the low natural flow rates of the gas. Nonetheless,

TABLE 16

Estimates of Undiscovered Recoverable Oil and Gas Resources by Petroleum Region*

Petroleum Regions	Crude Oil (Billion Barrels)			Natural Gas (Trillion Cubic Feet)		
	Low F_{95}†	High F_5	Mean	Low F_{95}†	High F_5	Mean
Onshore Regions						
1 - Alaska	2.5	14.6	6.9	19.8	62.3	36.6
2 - Pacific Coast	2.1	7.9	4.4	8.2	24.9	14.7
3 - Colorado Plateau, Basin and Range	6.9	25.9	14.2	53.5	142.4	90.1
4 - Rocky Mountains and Northern Great Plains	6.0	14.0	9.4	29.6	69.0	45.8
5 - West Texas and Eastern New Mexico	2.7	9.4	5.4	22.4	75.2	42.8
6 - Gulf Coast	3.6	12.6	7.1	56.5	249.1	124.4
7 - Mid-Continent	2.3	7.7	4.4	22.9	80.8	44.5
8 - Michigan Basin	0.3	2.7	1.1	1.8	10.9	5.1
9 - Eastern Interior	0.3	1.9	0.9	1.2	5.0	2.7
10 - Appalachians	0.1	1.6	0.6	6.4	45.8	20.1
11 - Atlantic Coast	0.1	0.8	0.3	<0.1	0.4	0.1
Total Onshore	41.7	71.0	54.6	322.5	567.9	426.9
Offshore Regions (Shelf and Slope)						
1A - Alaska§	4.6	24.2	12.3	33.3	109.6	64.6
2A - Pacific Coast	1.7	7.9	3.8	3.7	13.6	6.9
6A - Gulf of Mexico	3.1	11.1	6.5	41.7	114.2	71.9
11A - Atlantic Coast	1.1	12.9	5.4	9.2	42.8	23.6
Total Offshore	16.9	43.5	28.0	117.4	230.6	167.0
TOTAL UNITED STATES	64.3	105.1	82.6	474.6	739.3	593.9
LOWER 48 ONSHORE	36.1	62.0	47.7	288.6	525.9	390.3
LOWER 48 OFFSHORE	8.7	25.1	15.8	66.1	148.2	102.4

*Totals may not add due to rounding.

†F_{95} denotes the 95th fractile; the probability of more than the amount F_{95} is 95 percent. F_5 is defined similarly.

§Includes quantities considered recoverable only if technology permits their exploitation beneath Arctic pack ice -- a condition not yet met.

SOURCE: U.S. Geological Survey, *Estimates of Undiscovered Recoverable Resources of Conventionally Producible Oil and Gas in the United States, A Summary*, February 1981.

these 12 basins account for 35 percent of the total U.S. area (lower 48) thought to contain prospective tight gas. Estimates from these detailed appraisals were then extrapolated to the remaining 65 percent of the U.S. land area, to estimate the total tight gas resource base potential in the lower 48 states.

The study calculated resource and recovery estimates at five gas prices, three rates of return, and two levels of technology -- a base case (current technology) and an advanced technology case. The results of the assessment indicate a range of between 192 TCF and 574 TCF of tight gas as recoverable, depending upon price and technology (see Table 17). The potential additions to the conventional reserve base are almost equally affected by price and/or technology changes.

TABLE 17

U.S. Tight Gas Resource and Recovery Estimates
(Appraised and Extrapolated Areas)
(Lower 48 States)

	Appraised (12 Basins)	Extrapolated (101 Basins)	Total*
Prospective Area (Sections)	359,500	655,000	1,014,500
Productive Area (Sections)	53,000	68,500	121,500
Total Gas in Place (TCF)	444	480	924
Maximum Recoverable (TCF)	293	315	608
Base Technology -- Recoverable (TCF)†			
@ $2.50/MCF	97	95	192
$5.00	165	200	365
$9.00	189	215	404
Advanced Technology -- Recoverable (TCF)†			
@ $2.50/MCF	142	189	331
$5.00	231	272	503
$9.00	271	303	574

*Totals may not add due to rounding.

†15 percent discount rate of return and constant January 1, 1979, dollars.

SOURCE: National Petroleum Council, Unconventional Gas Sources, December 1980.

ENHANCED OIL RECOVERY POTENTIAL

In 1978 the Office of Technology Assessment (OTA) issued a report entitled Enhanced Oil Recovery Potential in the United States. By definition, oil recovered by enhanced techniques includes oil from a petroleum reservoir that cannot be economically recovered by conventional primary and secondary techniques. EOR methods include in situ combustion, steam injection, CO_2 miscible flooding, surfactant/polymer flooding, and polymer-augmented waterflooding.

OTA's assessment was based on a reservoir-by-reservoir analysis of the anticipated performance of EOR processes. The data base used was composed of 385 oil fields in 19 states, including 24 offshore fields, and contained 52 percent of the known remaining oil in place in the lower 48 states. National (lower 48) totals were extrapolated on the basis of state-by-state assessments.

OTA applied various price scenarios to EOR processes in developing its assessment. Because of the great increase in world oil prices since the study was completed, the results of the highest price per barrel should be emphasized. At the $30 per barrel case, about 49.2 billion barrels were considered recoverable, assuming high process performance (see Table 18). This estimate is about 96 percent of the 51 billion barrels presumed by OTA to be technologically recoverable, and again demonstrates the importance of price as well as technology in developing the total U.S. resource base.

TABLE 18

Estimates of Ultimate Recoverable Oil and Daily Production Rates from Enhanced Oil Recovery (Advancing Technology Case with 10 Percent Minimum Acceptable Rate of Return)

	Price Per Barrel	Ultimate Recovery* (Billions of Barrels)	Production Rates (Millions of Barrels Per Day)		
			1985	1990	2000
High-Process Performance					
Upper Tier	$11.62	21.2	0.4	1.1	2.9
World Oil	$13.75†	29.4	[illegible]	1.7	5.2
Alternate Fuels	$22.00§	41.6	1.[illegible]	2.8	8.2
Hypothetical	$30.00	49.2	--¶	--	--
More Than	$30.00	51.1	--	--	--
Low-Process Performance					
Upper Tier	$11.62		0.4	0.5	1.1
World Oil	$13.75	11.1	0.5	0.7	1.7
Alternate Fuels	$22.00	25.3	0.9	1.8	5.1

*These figures include 2.7 billion barrels from enhanced oil recovery processes that are included in the API estimates of proved and indicated reserves.

†$13.75 is the January 1977 average price ($14.32 per barrel) of foreign oil delivered to the East Coast, deflated to July 1, 1976.

§$22.00 per barrel is the price at which the Synfuels Interagency Task Force estimated that petroleum liquids could become available from coal.

¶Production rates were not calculated for oil at prices of $30 per barrel or higher.

SOURCE: Office of Technology Assessment, Enhanced Oil Recovery Potential in the United States, 1978.

The major environmental issue confronting oil and gas exploration and development in the 1980's concerns adequate access to government lands. In order to develop the nation's oil and gas resources, the industry must first be allowed access to the land to determine the extent of the resources and, if they are economic, be permitted access to develop those resources in an environmentally acceptable manner. The following discussion describes the land use, access, and permitting issues and the exploration and production segments' air, water, and waste management considerations.

This report does not directly address the socio-economic issues associated with exploration and production activities. These issues are indeed important, but, as they vary significantly from site to site, are beyond the scope of this report.

LAND -- ONSHORE

I. Land Access, Land Withdrawals, and Land-Use Planning

A. Historical Perspective on Federal Lands

The federal government currently owns nearly 728 million acres of onshore land in the United States, about a third of the nation's total land area of 2.3 billion acres (see Table 19). The vast majority of federal land is located in the 11 western states and

TABLE 19

Acres of Land Managed by Federal Agencies as of June 1, 1981*

Agency	Millions of Acres	Percentage of Total U.S. Onshore Land
Department of the Interior		
Bureau of Land Management	338.0	16.9
Fish and Wildlife Service	85.0	4.5
National Park Service	70.6	3.5
Department of Agriculture		
Forest Service	190.0	9.5
Department of Defense	35.0	1.7
Other Agencies	10.0	0.5
Total	727.6	36.6

*Source of data: Environmental Policy Center et al., Minerals and the Public Lands, 1981.

Alaska (see Figure 24). These lands include the remainder of the original public domain, lands acquired by the federal government, and land where the subsurface mineral rights were retained by the government when the land was sold to private interests. In addition, the federal government retains mineral rights to over 60 million acres of state and private land. While government land is managed by 68 federal agencies, departments, and bureaus, most of the land is controlled by the Departments of the Interior, Agriculture, and Defense.

Historically, government actions promoted access to this territory for settlement and resource development. The initial federal land policy was to:

> ...make public lands generally available for disposal --for agricultural settlement, for mineral development as grants to the states for various purposes, and to entrepreneurs willing to provide the public improvement to develop the West. The withdrawal or reservation of public lands was the only way in which land disposals could be controlled in a planned way.
>
> During the 19th century Congress enacted many statutes authorizing withdrawal of specific lands from the operation of these disposal laws Additionally, many other withdrawals and reservations were consummated by the Executive both with and without explicit statutory authorization.[2]

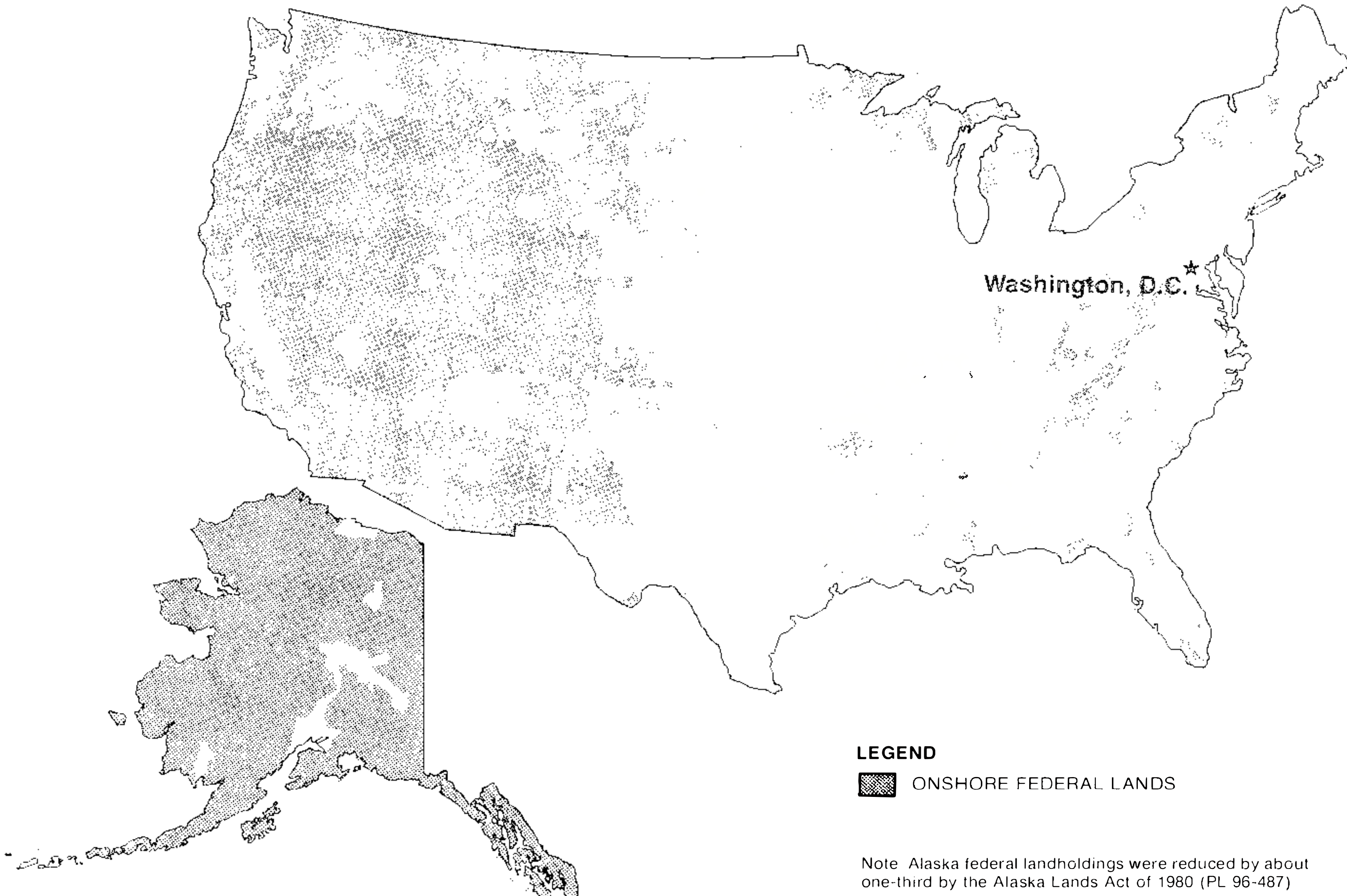
Historical and statutory precedent notwithstanding, certain Congressional and Executive Branch actions have served to restrict access to government lands. A major impediment to access for resource assessment of possible development has been the withdrawal of government lands through the operation of the various public land laws

Withdrawal of government lands

> ...means to withhold them from settlement, sale, or entry under some or all of the general land laws for the purposes of maintaining the status quo because of some exigency or emergency, to prevent fraud, to correct surveys of boundaries, to dedicate the lands to an immediate or prospective public use, or to hold the land for certain future action by the executive or legislative branch of government.[3]

Withdrawals of government land can take a variety of forms and have varying degrees of operation. Some of these are:

Federal statutes dedicating the land to specific uses, such as the creation of a national park or wilderness area (*de jure*)



SOURCE: Congressional Quarterly, Inc., from U.S. Geological Survey, April 1978.

Figure 24. Government Lands.

- Congressionally delegated withdrawal authority given to the Executive Branch for specific purposes, such as reclamation and power projects or for the preservation of land for historical or scenic purposes, or for nonconservation purposes such as Department of Defense facilities (de jure)

- Executive Branch assertion of an implied authority to withdraw land for special purpose use and/or for study purposes (de facto).

- Judicial review resulting in delay (de facto).

Two major reports completed in the 1970's concluded that it was impossible to determine how much land has been withdrawn, restricted, or made unavailable to mineral entry or leasing de jure and de facto.[4] The absence of accurate records within the federal agencies, and their failure to act on permit applications, which become withdrawals in fact, has made de jure and de facto determinations difficult.

The shift of administrative control of lands from agencies with multiple-use management policies to agencies with single or restrictive land-use policies has also had an impact on land withdrawal. Both the Bureau of Land Management (BLM) and the U.S. Forest Service have broadly defined multiple-use mandates such that these agencies exhibited a net loss in total acreage managed during the 1958-1978 period. BLM historically transfers control of such lands to other agencies once certain parcels have been classified for specific, restricted use. Such interagency assignment actions may remove more federal lands from eventual access. For example, lands managed by the National Park Service are withdrawn almost entirely from the operation of mineral laws by statute.[5] Land managed by the Fish and Wildlife Service (FWS) is severely restricted by agency policy, with exceptions made only where oil and gas resources would be subject to subsurface drainage by operations on adjacent tracts not controlled by FWS.[6]

B. Authority and Mechanisms for Federal Land-Use Planning

1. Constitutional Authority

The underlying authority for Congressional jurisdiction over the disposition of lands in the public domain is granted by the Constitution (Article IV, Section 3, Clause 2). Congress has delegated certain authority for withdrawals to the Executive Branch by statute; two examples are the Reclamation Act of 1902 and the General Withdrawal Act.[7] Further, the Executive Branch has assumed certain implied authority as the basis for some withdrawals.[8] Although the Secretaries of Agriculture and the Interior were given wide-ranging authority for the multiple-use management of government lands by the Multiple-Use and Sustained-Yield Act of 1960 and the Multiple-Use Act of 1964, Congress retained exclusive power over withdrawals for nondevelopment purposes, such as national parks and wilderness areas.

2. Legislative Authority and Agency Land-Use Planning

a. Forest Service

Over the years, the courts have generally held that the Organic Act of 1897 gives the Forest Service fundamental authority to manage all national forest lands. Today, the Forest Service manages the National Forest System, which includes National Forests, National Grasslands, Land Utilization Projects, and Purchase Units.

The 1960 Multiple-Use and Sustained-Yield Act gave the Forest Service its first cohesive planning mandate, followed by the Forest and Rangeland Renewable Resources Planning Act in 1974. In 1976 the Resources Planning Act was amended by the National Forest Management Act, which set forth the process by which land and resource management planning should be conducted. In 1979, final rules and regulations were promulgated, providing the Forest Service statement of intentions for implementing the 1974 and 1976 statutes. The statement of intentions for Forest Service planning involves three levels: national, regional, and individual forest plans. By statute, plans at all levels must be in effect by 1985.

- The national plan includes an analysis of the uses of, supply of, and demand for natural resources. National goals and objectives are formulated as a range of outputs, which are then reassigned to regions and incorporated into regional plans. The national resource plan, called the Renewable Resource Program, sets forth a 40-year program; it must be revised every five years, commencing in 1980.

- Regional plans respond to the direction of the national program. Issues and concerns are formulated and alternative strategies developed, together with standards and guidelines for various resources and activities. The broad national targets are allocated through the region to individual forests. Regional plans are presently being developed and published.

- Forest plans respond to regional directives with consideration for local supply and demand, economic efficiency, community stability, and potential environmental effects. There are approximately 154 national forests for which land management plans are being prepared.

Applications for petroleum exploration and development must first be evaluated by the Forest Service to determine if the lands are available (not formally withdrawn or involved in a land exchange). Existing land management plans are consulted to determine appropriate stipulations, such as compatibility with existing uses, control of adverse environmental impacts, and prompt reclamation of disturbed lands. Oil and gas lease applications involving National Forest System lands result in a Forest Service recommendation to BLM, which acts as lessor, whether to award the lease.

Another important aspect of the Forest Service's duties is its direct involvement in implementing the Wilderness Act of 1964. The

Act established a 15 million acre system of wilderness areas. Since that time, 64.8 million acres have been added In addition to the 79.8 million acres now designated as wilderness, as many as 9.9 million acres could be included under the Forest Service's second Roadless Area Review and Evaluation (RARE II) program. Another 7.6 million acres of forest lands, known as future planning areas, could be added to the National Wilderness Preservation System (NWPS). Also, 23.7 million acres of BLM Wilderness Study Areas could be made part of the system. Thus, through these reviews alone, the wilderness system could eventually exceed 120 million acres -- more than 16 percent of all federal onshore lands.[9]

While the Wilderness Act provides that these lands are open to oil and gas exploration activities until December 31, 1983, only 24 oil and gas leases have been issued in wilderness areas over the last decade. The "wilderness" designation is the most exclusionary single-use designation that can be applied to federal lands. Motorized vehicles, roads, and permanent campsites are prohibited; travel in these areas can only be on foot, on horseback, or by canoe. Thus, unlike national parks, relatively few persons enter wilderness areas, and for all practical purposes oil and gas exploration and development activities are denied access to such areas.

In the past, oil companies have been reluctant to attempt to explore on wilderness lands when other prospective acreage, not subject to restrictions under the Wilderness Act, was more readily accessible. But the need to increase domestic energy production and reduce dependence on foreign oil has provided an impetus to explore for oil and gas on certain wilderness lands. It has been demonstrated repeatedly that oil and gas facilities can operate with only temporary and minimal disturbance to the environment.

b. Bureau of Land Management

The 1976 Federal Land Policy and Management Act (FLPMA) endowed BLM with major responsibility for developing total land-use plans to achieve mandated objectives on BLM-managed lands. This responsibility far exceeded BLM's initial responsibilities for simple grazing administration and thrust BLM into a transition period in which regulations and procedures are still being written and clarified.

With FLPMA, Congress repealed all existing executive withdrawal authority, both statutory and implied, except the President's authority to create national monuments.[10] Section 204 of FLPMA substantially limited the Executive Branch authority to withdraw government lands, providing detailed guidelines by which the Secretary of the Interior is authorized to make, modify, or revoke withdrawals. In accordance with Section 204, BLM proposed and promulgated regulations for the withdrawal of government lands. These regulations establish a formal process for Executive Branch action, including the opportunity for public participation.[11]

FLPMA was intended to make coherent the government land management policies of BLM. At the center of FLPMA's comprehensive management plan are the principles of sustained yield and multiple use, with special recognition of the nation's need for domestic sources of minerals, food, timber, and fiber. In addition, FLPMA also recognizes a need for land withdrawals.

Congress identified a number of policy objectives in adopting FLPMA:

- A general inventory of all government lands and their resource values was needed. Closely related to the general inventory is the special inventory required as a part of the BLM Wilderness Study. Under these provisions, BLM is to undertake a special review of government lands in roadless areas of 5,000 acres or more. The Wilderness Study is to be completed by 1991 and is intended to identify areas that might be included in the NWPS established under the Wilderness Act. As of November 18, 1981, BLM had inventoried all 173.7 million acres of roadless areas under its jurisdiction. Over 149 million acres were determined to lack wilderness characteristics, and 24.3 million acres were determined to have wilderness characteristics.[12] Those areas not designated for wilderness will be managed under land-use plans using the principles of sustained yield and multiple use and in accordance with several other criteria set forth in FLPMA as part of the land-use planning process.

- Management for certain purposes may necessitate withdrawal. As an exception to the general principle of sustained-yield and multiple-use management, certain lands may be withdrawn under Section 204. For areas of less than 5,000 acres, the Secretary has the discretion to withdraw lands for specific periods of time, depending on the nature of the withdrawal. For areas of 5,000 acres or more, however, the Secretary may only recommend withdrawal for a period of up to 20 years. Without Congressional approval, such withdrawals lapse within 90 days of his recommendation. FLPMA also provides that, if an emergency exists, Congress or the Secretary can immediately withdraw lands, but for no longer than three years.

- Areas of critical environmental concern (ACEC) deserve prompt protection. ACEC are identified as areas "within the public [government] lands where special management attention is required...to protect and prevent irreparable damage to important historic, cultural, or scenic values, fish and wildlife resources or other natural hazards." Priority treatment is to be given to the identification of ACEC during the inventory of government lands, resources, and values and to maintenance once the inventory is completed. The ACEC designation could result in the development of a rational management system; however, the potential for single-use management invites its use as a substitute wilderness program without size limitation.

Currently, 79 areas have been designated under the ACEC program, covering more than 620,000 acres, with approximately 600,000 acres in the state of California. The legislation does not limit the acreage of an ACEC. One of the ACEC in the California Desert Plan, for example, contains some 145,000 acres and some others within that plan exceed 36,000 acres each. BLM has indicated that as many as 275 million acres of federal lands may be eligible for ACEC designation. Thus, many thousands of acres could be nominated for and designated as ACEC and, notwithstanding the multiple-use language in the guidelines, large amounts of government land could become unavailable for oil and gas exploration and development.

Initial BLM plans were formed under a Management Framework Plan (MFP). In 1979 new regulations introduced a broadened planning document known as a Resource Management Plan (RMP). None of these new plans exists to date, though several dozen are in various stages of preparation. By 1985 MFPs will be phased out, replaced by RMPs. As it is expected to take about four years to complete an RMP, it will be the early 1990's before all BLM plans are completed under the new system. Thus, a new third planning document, called a "Transition Management Framework Plan," will exist for about a decade.

Leasing decisions in a resource area are limited to those permitted by the plan. If a BLM plan does not include leasing, then an environmental impact statement (EIS) must be made and the decision whether to lease be made accordingly.

c. Other Agencies and Joint Agency

The need for joint agency agreements arises from multidimensional ownership patterns and statutory responsibilities. Both horizontal (different adjacent surface) and vertical (subsurface different than surface) ownerships or responsibilities offer a variety of permutations that must be accommodated. The surface problem is one of access, providing opportunity to explore, drill, and transport. The subsurface problem is one of title for sale, lease, severance, and royalty purposes.

BLM leases federally owned subsurface minerals, regardless of which federal agency manages the surface. Subsurface minerals may be owned privately, by Indian tribes, or by government entities. Similarly, the surface may be independently owned by any of these groups. Since it is not possible to divorce mineral operations from surface management, federal agencies have developed cooperative procedures to coordinate their mutual responsibilities.

In November 1980 an inter-agency agreement was signed to promote a cooperative relationship among BLM and Forest Service and other agencies (most notably the Soil Conservation Service, Science and Education Administration, Fish and Wildlife Service, and the National Park Service). Signatories are to prepare and exchange appropriate plans, schedules, and data for major national resource

issue planning and decision-making. This is a relatively new program, thus far directed at interchange of public involvement data only.

3. Land-Use Planning Issues

Land-use plans developed to date inadequately address oil and gas exploration and development. The NPC is concerned that the management processes, in their present state as reflected in those plans, could perpetuate a climate of uncertainty and restriction of petroleum development.

Three topic areas will highlight this concern: definition, data adequacy, and attitude.

- Definition. Planners are not agreed on a definition of multiple use. Whether that term means co-existence or partitioned exclusivity, or both, is unclear. The issue is critical, because the statutory language mandating multiple use has been interpreted differently. Forest Service language derives from the 1960 Multiple-Use and Sustained-Yield Act and also implements provisions of the 1974 Forest Range Land Renewable Resources Planning Act, amended by the 1976 National Forest Management Act. The thrust of these acts has been to establish a sustained yield of forest products and services towards target goals. The effect has been to set forth a restricted definition of multiple use, as it is limited to surface use only and does not take into account subsurface resource goals. The definition in FLPMA is broader, calling for resource utilization in the combination that will best meet the present and future needs.

- Data Adequacy. Data on petroleum potential is generous in highly drilled areas but meager or non-existent in undrilled areas. Data overload from other resources, competing with a dearth of petroleum-related data in undrilled areas, leads to increased attention to those resources where the plentiful data assures sound planning decisions. The absence of data may also lead to incorrect conclusions about the presence of petroleum. Concurrently, Congressional policy dictates multiple use of the lands, including oil, gas, and other minerals. The use of the present planning process, dependent as it is on data adequacy, hinders this Congressional policy.

- Attitude. Planners are inclined to regard petroleum operations as more damaging to the environment than has been demonstrated. There is a tendency to prepare for the worst possible case, ignoring countless examples of trouble-free oil and gas operational co-existence with other resource values. Some examples are the Aransas National Wildlife Refuge, a protected whooping crane nesting ground in the midst of an operating oil field; the caribou movement under and over the Alaskan pipeline; and offshore production platforms that have become marine sanctuaries in themselves.

C. Status of Land Withdrawals

The consequences of land withdrawals have been the subject of public debate since the early 1970's.[13] Five federal reports attempted to assess the magnitude of the effect of withdrawals on resource development:

- General Accounting Office, Improvements Needed in Review of Public Land Withdrawals -- Land Set Aside for Special Purposes, 1976.
- Department of the Interior, Final Report of the Task Force on Availability of Federally Owned Mineral Lands, 1977.
- Office of Technology Assessment, Management of Fuels and Non Fuel Minerals in Federal Lands, 1979.
- General Accounting Office, The U.S. Mining and Mineral Processing Industry: An Analysis of Trends and Implications, 1979.
- General Accounting Office, Actions Needed to Increase Federal Onshore Oil and Gas Exploration and Development, 1981.

In its 1976 report, the General Accounting Office (GAO) found that no mechanism was available by statute for the periodic review of withdrawals of government lands. Upon investigation, GAO determined that records of withdrawals were non-existent, and that procedural problems within administering agencies delay the processing of revocations of withdrawals that are no longer appropriate and the return of the land to the operation of the public land laws. Consequently, not only was the accounting system for withdrawals in a state of chaos, but the restoration of government lands to multiple-use status lagged.

1. Administrative Procedures and Judicial Actions that Create De Facto Withdrawal of Government Lands

With the enactment of FLPMA, Congress affirmed once again a broad multiple-use management philosophy for government lands. However, both the agencies in charge of government lands (BLM and the Forest Service) and the courts have restricted access and withdrawn lands either explicitly or tacitly by their inaction.

Agencies responsible for government lands have, through administrative practices, been able to manage the lands by narrow interpretations of multiple-use management. Since each agency has been created to manage lands under its jurisdiction for specific resource values, administrators of those agencies have chosen to focus their activities primarily on single land-use practices rather than upon concurrent multiple uses. Various actions and discretionary decisions by administrators may also result in unintentional *de facto* withdrawals of lands from certain resource uses.[14]

Administrative withdrawals can be accomplished by an agency's failure to act, such as by the failure to issue leases and permits or failure to complete management plans. Other restrictions that impede resource exploration and development can be added unilaterally to leases, permits, and operating plans. The "no surface occupancy" lease stipulation is an example.

Delays in issuing leases, such as those created by failure to promptly list lands eligible for inclusion in the simultaneous leasing system, can constitute a *de facto* withdrawal. A recent U.S. District Court decision held that delayed action on issuing leases in two RARE II Wilderness Planning Areas constituted an informal withdrawal of the lands.[15] As a result, the Court ordered the Secretary of the Interior to issue regulations and guidelines providing standards by which federal oil and gas leases could be approved, rejected, or suspended.

Judicial review, like administrative policy, may create *de facto* withdrawals. In the case of *Sierra Club vs. Butz* the court created a *de facto* withdrawal that extended to surface resources when it upheld the Forest Service's adoption of "no surface occupancy" stipulations in some oil and gas leases.[16] A more recent case involved the reversal of a Forest Service decision to allow developmental work in a number of roadless survey areas. The Forest Service determined that those areas could be opened to non-wilderness uses. On the basis that the agency's RARE II final EIS was inadequate, the court recommended reconsideration of the wilderness values of the areas.[17] This decision could set a precedent requiring a site-specific EIS prior to the rededication of lands for multiple-use purposes.

2. The Extent of Withdrawals of Government Land from Mineral Entry and Leasing

a. Department of the Interior and Office of Technology Assessment Reviews

Both the Department of the Interior (DOI) and OTA have estimated the extent of restrictions on mineral access to federal lands. The classification of federal lands used in the DOI and OTA studies are as follows:

- "Closed" -- includes lands formally closed to mineral development, either by statute (e.g., national parks) or by a published withdrawal order (e.g., wildlife, military, or oil shale land).

- "Highly restricted" -- includes lands that, while formally open to mineral development, are restricted by statutory conditions (e.g., power sites); statutory and administrative conditions (e.g., wilderness areas or certain reclamation project lands); or administrative conditions (e.g., BLM's primitive and natural areas) to such an extent that mineral development is greatly discouraged, although it sometimes does occur.

- "Moderately restricted" -- includes lands that are generally open to mineral development, although they may be closed to development of a few minerals or there may be certain pre-conditions to mineral development (e.g., the preparation of an EIS).

- "Slight or no restriction" -- includes all federal land that is generally subject to multiple-use management.[18]

The conclusions and recommendations of both the DOI and OTA studies are similar in their call for a more comprehensive "system of inventory and review of withdrawals and restrictions on mineral development."[19] In fact, the Secretary of the Interior is specifically directed to conduct such an inventory by Section 201 of FLPMA.[20] Echoing the conclusions of the Public Land Law Review Commission of 1970, OTA observed in 1979 that:

> ...[t]here is a need for a cumulative state-by-state and nationwide accounting of the use of Federal land. Such an accounting should permit Federal management of minerals and land to progress beyond its current essentially ad hoc procedures. The land use planning process already underway on Federal land could include a unit-by-unit summary of land status, including withdrawals, which is aggregated at successively higher levels of the relevant agencies and culminates in a comprehensive land status report. Computerization of the land status records at the local level might greatly simplify statistical reporting and increase the accuracy, timeliness, and ease of maintaining those records.[21]

b. Bureau of Land Management Review

Under the provisions of FLPMA, BLM was assigned the responsibility for conducting an inventory of all government land withdrawals. Restricted in scope to coverage in 11 western states, the results of the partial inventory were released in January 1980.[22] At that time, the BLM Director stated that:

> ...[m]any of the withdrawals...[examined] date back to the turn of the century. In a significant number of cases their cancellation is long overdue...[b]ut through the years, the tendency was for the withdrawal to remain in force long after the need for it had passed.... Today with our growing energy crisis there is a need to make as much land as possible available for mineral development.[23]

Overall, BLM decided that it was responsible for conducting a review of withdrawals on only 67.9 million acres since FLPMA specifically excluded from consideration:

> ...public lands administered by the Bureau of Land Management, and certain lands in the National Forest System which are not closed to appropriation under the Mining Law of 1872, or to leasing under the Mineral

Leasing Act of 1920; certain Indian Reservations and other Indian holdings; the National Park System; the National System of Trails; the National Wild and Scenic Rivers System; the National Wildlife Refuge System; and other lands administered by the Fish and Wildlife Service or by the Secretary through the Fish and Wildlife Service.[24]

At the end of 1980, final decisions were announced allocating some 24.3 million acres in 967 tracts to Wilderness Study Area designation. The next phase in a Wilderness Study Area evaluates all resources and activities in relationship to each other. This analysis will generate a recommendation to the President before 1991 as to the preferred utilization. The President must then make his recommendation to Congress before 1993. If the recommendation to the President is for wilderness designation, then a minerals inventory must be made of the area. Wilderness Study Areas are incorporated into Management Framework or Resource Management Plans. While they are in the study phase, they are managed under special guidelines that seek to protect the wilderness characteristics on an interim basis. BLM has given highest priority to reporting to the President by September 1985 as many Wilderness Study Areas as possible that contain energy-related resource conflicts. For BLM Wilderness Study Areas, oil and gas activity is practically impossible unless an operator had been physically working a lease prior to October 1976.

The amount of federal land actually restricted by the Wilderness Review Programs of BLM and the Forest Service is not clear. The case of California vs. Bergland prevented release to multiple use of California RARE II lands of the Forest Service found not to have wilderness characteristics.[25] Until the appeal of that case is resolved, the status of released lands nationwide is uncertain. The Forest Service has no uniform policy for leasing or withdrawing those RARE II wilderness study lands not already leased prior to the onset of the RARE II evaluation. Even though the lands may be leased, restrictive stipulations may keep tracts in the severely restricted category. The BLM's Wilderness Study Areas have two different classes of restrictions placed on oil and gas leases within them. As a result of DOI's decision not to appeal the District Court's holding regarding leases issued prior to enactment of FLPMA (October 21, 1976), such leases will be administered according to the requirements of the BLM's Interim Management Policy, which GAO characterized as applying "more restrictive standards" than the Wilderness Act itself.[26,27]

c. General Accounting Office Review

The 1981 GAO report underscores the fact that the problem of obtaining accurate estimates of withdrawals still exists because several agencies, including those managing the largest areas of government land, do not maintain central records of such withdrawals.

The GAO report covers the total amount of federal land and the portion considered by USGS to be prospectively valuable for oil and

gas for 48 states (excluding Alaska). Of the 410 million total federal acres in these states, 261 million were considered to be prospectively valuable. GAO estimated that 64.1 million acres of federal lands were closed to federal leasing as of 1979, and as of February 1980 there were withdrawal applications pending on an additional 4.3 million acres of BLM land. Of the 64.1 million acres that have been withdrawn, more than 48 million acres were closed through formal withdrawals and 16 million through administrative actions.[28]

The GAO study includes a detailed review of the federal lands in Colorado, Mississippi, Nevada, New Mexico, and Wyoming that have been closed to oil and gas leasing. Of the 20 million acres GAO identified as closed to oil and gas leasing, at least 11 million acres are considered prospectively valuable for oil and gas. Another 16.5 million acres in the five states reviewed could be affected by the wilderness program. At least 8.5 million acres of these lands have some likelihood of containing oil and gas. USGS defines "prospectively valuable" oil and gas lands as areas that offer some possibility for the occurrence of oil and gas. The designation does not guarantee that such lands will be productive, as that can be determined only by actual drilling.

Of the 20 million acres withdrawn in those states, 14 million acres were formal withdrawals and 6 million acres were administrative withdrawals. Many of these withdrawals have no termination dates. Thus, units cannot be assembled for development and eventual production on these lands. At least 55 percent of these closed lands have been identified by USGS as prospectively valuable for oil and gas.[29] New Mexico has the highest percentage of withdrawn lands with oil and gas potential. Of the 3.9 million acres closed to leasing in New Mexico, 3 million acres, or 76 percent, are considered to be prospectively valuable for oil and gas. Nevada, with 6.6 million acres withdrawn, has more valuable oil and gas acreage closed than New Mexico, but this represents a smaller portion of total withdrawals in the state.

GAO estimated that 312.6 million barrels of oil and 156 billion cubic feet of gas could be contained in the withdrawn lands in the five review states. Another 387.4 million barrels of oil and 162.4 billion cubic feet of gas could be affected by BLM and Forest Service wilderness programs.

d. Environmental Policy Center Review

The Environmental Policy Center's 1981 report, Minerals and the Public Lands, reported a total land withdrawal figure of 194.6 million acres, including Alaska, compiled from the BLM inventory withdrawal review, Congressional testimony, DOI's Public Land Statistics, 1979, and personal communications.

3. Alaska Public Land Withdrawals

In Alaska, withdrawals account for the largest aggregate area of federally held land. Executive and Congressional withdrawals

promulgated without a comprehensive resources review considering the needs of the state of Alaska or the nation have given rise to land-use conflicts. Land withdrawals in Alaska are a good example of the problems created when extensive holdings of government land are federally withdrawn. This subject is discussed in the 1981 NPC report, U.S. Arctic Oil and Gas.

II. Onshore Leasing and Bidding Systems and Lease Stipulations

A. Status of Government Lands

1. Federal Government Lands

Federal government lands are held in trust by the federal government and owned by the people of the United States. As shown on Table 19, the federal government owns nearly 728 million acres of onshore land in the United States -- about one-third of the nation's total area.

2. State Lands

All of the western states except Texas are government land states that were created by acts of Congress from land held in the public domain. The enabling legislation contained provisions for state land grants to be used for "welfare" purposes, such as schools, universities, public buildings, and improvements. Although the major portion of state lands were derived from such legislation, states also acquired land through other means, such as foreclosure of state loans, purchase, or eminent domain.

State lands were intended to provide assets that could be liquidated to produce funds for the designated uses. Although some states sold their land immediately and completely, by the early 1900's states tended to reserve all or part of the minerals rights when properties were sold. Each state created a commission or board to manage state lands and the revenues derived from them. These boards promulgate rules and regulations and establish fees for acquiring mineral rights, leasing, exploration, and production.

3. Indian Lands

American Indian lands in the lower 48 states comprise over 52 million acres. Virtually all of these Indian lands are west of the Mississippi, and many are located within oil and gas producing regions. Fourteen Indian tribes and numerous individuals currently are involved in oil and gas production on Indian lands. In 1980, oil production on Indian lands totaled 37 million barrels, and natural gas production was 115 billion cubic feet.[30]

The tribal land and resource base was greatly eroded by the General Allotment Act of 1887, which opened reservation lands for land grants to individual tribal members. Between 1887 and 1934, 90 million acres of tribal lands were transferred to individual Indian ownership. This practice was ended with the passage of the

Indian Reorganization Act in 1934. In addition to stopping allotments, the Indian Reorganization Act reasserted the principles of tribal sovereignty and the sanctity of the treaties. It also authorized the Secretary of the Interior to acquire lands on behalf of tribes.

Tribal and individual Indian property rights enjoy a legal status distinct from public or private property. The United States holds Indian lands and resources in trust for the perpetual and beneficial use of Indian people. The Constitution vests authority over Indian affairs exclusively in the Congress. Congress, in turn, has developed a special body of law governing Indian affairs. The Secretary of the Interior administers these laws and fulfills the government's fiduciary obligation to Indians.

Congress has specified the terms under which Indian oil and gas resources may be developed. The law prohibits any sale, grant, or other conveyance of Indian property or interests therein. Indian tribes and individuals may enter into limited term agreements for the development of their oil and gas resources pursuant to several Indian leasing laws. Most current oil and gas operations are conducted under the 1938 Indian Mineral Leasing Law. Both Congress and the courts have preserved tribal control over tribal resource development. No lease or agreement will be valid without the written approval of the governing body of the tribe and the Secretary of the Interior. Similar consent provisions apply to leases for individual Indian lands.

B. Petroleum Development on Government Lands

As of 1980, almost 450 million acres, or about 20 percent of the total U.S. land base, was under lease for oil or gas exploration and/or production. Of this total acreage under lease, only about 50 million acres have proven to be productive. Thus, about 400 million acres are under lease in areas that are nonproductive or remain to be tested for the existence of oil or gas. Shown on Figure 25 is the acreage that is under lease on lands controlled by the federal government as well as that under lease on private lands. Federally controlled lands include acreage on government and Indian lands. The acreage on government lands is almost 30 percent of the entire acreage under lease.

In 1980, federal offshore lands accounted for more than 9 percent of U.S. crude oil and condensate production and 23 percent of domestic natural gas producion. Onshore, federal lands (excluding Indian lands) provided more than 4 percent of all domestic crude oil and natural gas liquids production and more than 5 percent of our natural gas.[31]

C. Government Lands Leasing and Bidding Systems

1. Federal Lands

The present provisions for leasing oil and gas under the Mineral Leasing Act of 1920 are summarized below. The Secretary of

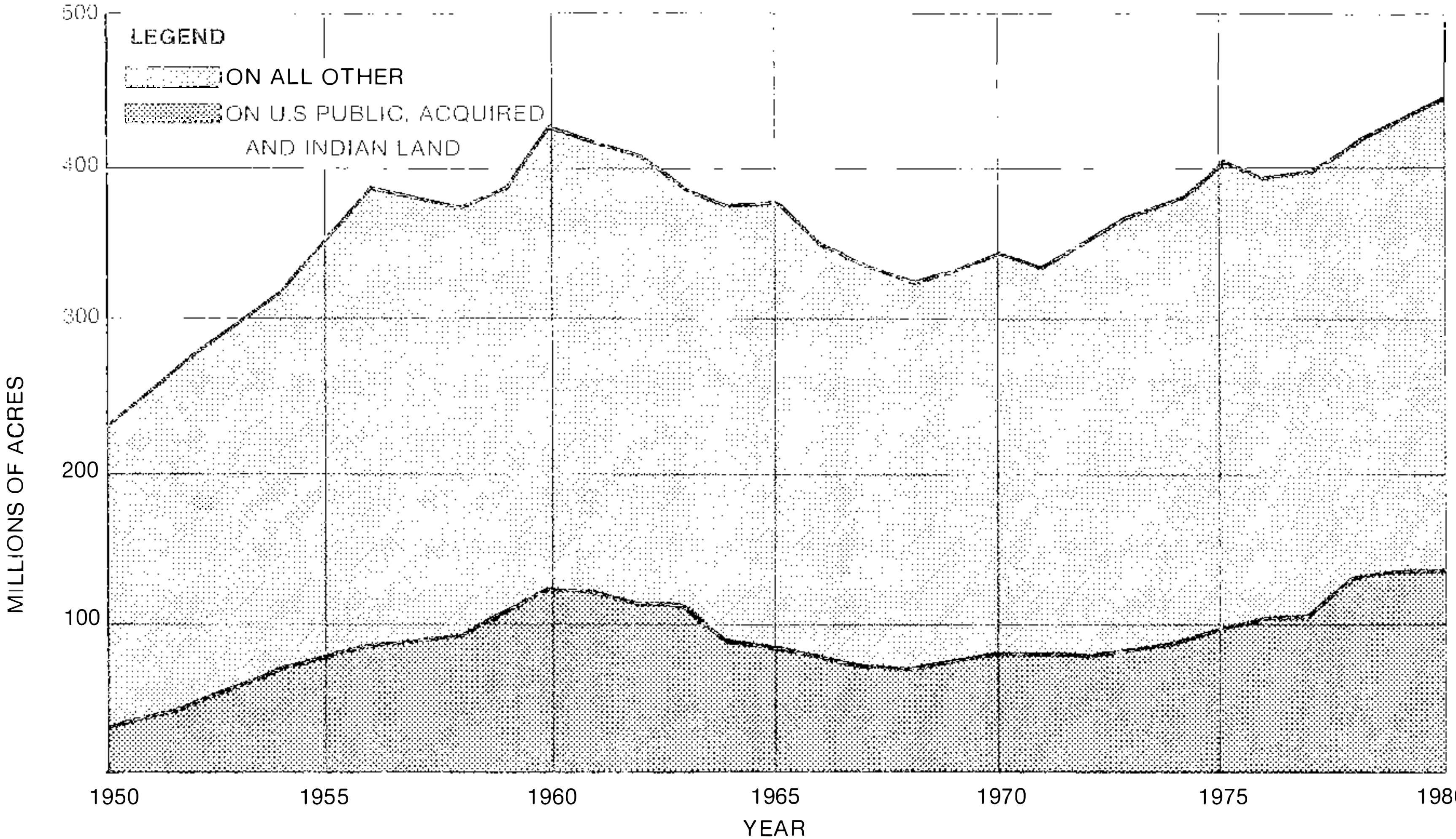


Figure 25. Total Productive and Nonproductive Acreage Under Lease for Oil and Gas in the United States—1950-1980.

SOURCE: Independent Petroleum Association of America.

the Interior is not obligated to lease acreage in areas where he believes leasing is not in the public interest.

A lease term is for a period of 10 years or as long thereafter as oil or gas is produced in paying quantities. Any lease on which active drilling is underway at the expiration date is granted a two-year extension

a. Competitive

All lands within the known geologic structure (KGS) of a producing oil or gas field must be leased competitively to the highest qualified bidder.

- Competitive leases are limited by law to a maximum of 640 acres.

- Royalty payments must not be less than 5 percent, and leases are presently issued on a sliding scale basis from 12 1/2 to 25 percent, depending upon monthly production per well.

- Competitive leases carry an annual rental of $2.00 per acre.

- Leases can be transferred or assigned, with the lessee being able to assign all or part of his interest in the leases to one or more parties. He can also assign part of the acreage, which in effect creates a new lease.

Regulations specific to competitive leasing are not extensive. A KGS is defined quite strictly in the BLM regulations, as "the trap in which an accumulation of oil or gas has been determined by drilling and determined to be productive, the limits of which include all acreage that is presumptively productive."[32] USGS regulations do not define the KGS as such, although over the years it has defined the KGS of a producing oil or gas field as the trap, whether structural or stratigraphic, in which an accumulation of oil or gas has taken place. The limits of such structures include all acreage that is presumed to be productive.

b. Noncompetitive

Land that is not presently under lease is available to the first qualified applicant who submits an application, together with the first year's rental and a $25.00 filing fee. Applications to lease that cover open lands and that are received in the same mail or over-the-counter at the same time, are considered as being filed concurrently; these leases will be established by a public drawing.

All lands that are not within a KGS and that are covered by cancelled or relinquished leases, leases that automatically terminate for nonpayment of rental, or leases that expire by operation of law at the end of their primary term or extended terms are subject to leasing only in accordance with the regulations relating to simultaneous filings. Notices of the availability of these lands

are posted in the BLM office in the state at the start of business on the first working day of January, March, May, July, September, and November. Lease applications for the lands may be filed from the time of posting until the close of business on the 15th working day thereafter.

After the winning applicant of a particular tract or parcel has been notified by the BLM, the executed lease agreement and the applicant's rental payment must be filed with the BLM office within 30 days. Noncompetitive leases carry an annual rental of $2.00 per acre; the royalty for noncompetitive leasing is 16 2/3 percent.

c. Lease Issuance on Wilderness Lands

The vast majority of wilderness areas are located on lands managed by BLM or the Forest Service. Lease issuance in those areas has become a great concern because of the time constraints in the Overthrust Belt, which lies along the general Rocky Mountain front from Canada to Mexico. Government records show that 24 leases have been issued in wilderness areas over the past 10 years:

- Fourteen in the West Elk Wilderness in Colorado, issued in 1972 and 1973
- Four in the Absaroka Beartooth Wilderness in Montana, issued in 1979
- Three in the Bridger Wilderness in Wyoming, issued in 1974
- Three in the Capitan Wilderness in New Mexico, issued in 1981.

Through the end of 1981 no drilling had occurred on any of these leases. In fact, issuance of the three leases in the Capitan Wilderness sparked such controversy that Congress shortly thereafter passed a resolution temporarily banning any future leases in wilderness areas until mid-1982.

Some lease applications on lands managed by the Forest Service lying within RARE II areas have been filed for up to seven years without being issued. Even those applications that do not lie within environmentally sensitive areas often await approval of the managing agency for anywhere from two to six months. This problem does not arise in competitive leasing, since the majority of these leases are not located in environmentally sensitive areas. These leases generally take from 30 to 60 days to issue, and are issued with whatever stipulations were specified in the notice for the sale.

2. State Lands

There is a wide diversity of state bidding and leasing systems. Table 20 provides examples of how some states lease their state lands.

TABLE 20

Examples of State Leasing and Bidding Systems

State	Bidding System	Lease Term	Lease Rentals	Lease Royalties	Maximum Size of Lease	Approximate Time of Lease Issuance
Alaska	Noncompetitive (not being used) At discretion of Commissioner and after publication of notice Competitive Sealed bid with any combination of: (a) Bonus bid (b) Royalty bid (c) Net profits	Not less than 5 years or more than 10 years, and "as long thereafter as oil and/or gas is produced in paying quantities" -- Established by Commissioner in Sale notice	$1.00/acre/year- increase 50¢/acre/ year through 5 years -- after 5 years, Commissioner can raise at his discretion (but cannot more than double)	Bid item - Fixed, sliding scale, net profits, or combination of any or all	5,760 acres	Less than 30 days after bid award
California	Competitive Sealed bid with any or all of: (a) Cash bonus plus sliding scale royalty (not less than 16-2/3%) (b) Sliding scale on oil (c) Fixed royalty of not less than 16-2/3% (d) Net profits bonus	20 years and "as long thereafter"	$1.00/acre/year	Fixed: Bid item (but not less than 16-2/3%) Sliding scale: Bid item	5,760 acres	30-60 days after bid award
Colorado	Competitive Oral bidding	5 years, and additional 5 year extension, and "as long thereafter"	$1.00/acre/year -- first 5 years $ commencing beginning of 6th year	12-1/2%	640 acres	Less than 60 days after bid award
Idaho	Competitive Oral bidding	10 years and "as long thereafter"	$1.00/acre/year -- first 5 years, $2.00/acre/year -- commencing beginning of 6th year, $3.00/acre/year -- commencing beginning of 11th year	12-1/2% (may be higher if advertised in notice of lease sale)	640 acres	
Louisiana	Competitive Sealed bidding, with any or all of: (a) Cash bonus bid (b) Royalty bid	3 years (onshore) and "as long thereafter"	Bid item (but not less than 1/2 of cash bonus bid offered)	Bid item (but not less than 12-1/2%)	2,500 acres (by Board policy) 5,000 acres (by statute)	10-20 days after bid award
Montana	Competitive Oral bidding	10 years and "as long thereafter"	$1.50/acre/year for full term of lease plus $1.25/acre/year commencing 6th year (non-drilling penalty)	Gas -- 12-1/2% Oil -- Sliding scale Bbl/Well Rate 0-3,000 12-1/2% 3-6,000 17-1/2% Over 6,000 25%	640 acres	30-60 days after bid award

TABLE 20 (Continued)

State	Bidding System	Lease Term	Lease Rentals	Lease Royalties	Maximum Size of Lease	Approximate Time of Lease Issuance
Nevada	Negotiated with Administrator of State Lands	Negotiated	Not less than $1.00/acre/year	15%	1,280 acres	30-60 days
New Mexico	Competitive Can be either oral or sealed bid, at discretion of Commissioner	10 years and "as long thereafter"	10¢ to $1.00/acre/year, at discretion of Commissioner (notice must be given prior to sale)	12-1/2% or 16-2/3% at discretion of Commissioner (notice must be given prior to sale)	6,400 acres	14 days after bid award
North Dakota	Competitive Oral bidding	5 years and "as long thereafter"	$1.00/acre/year	16-2/3%	160 acres	30 days after bid award
Oklahoma	Competitive Sealed bid	5 years and "as long thereafter"	$1.00/acre/year	18-3/4%	No statutory limitation but generally not larger than 160 acres	30 days after bid award
Texas	Competitive Sealed bid, with any or all of: (a) Cash bonus bid (b) Royalty bid	3 years (onshore) and "as long thereafter"	$5.00/acre/year	25% (except for 20% on Far West Texas wildcat acreage)	640 acres	30 days after bid award
Utah	Competitive Sealed bid Noncompetitive (not being used at present) Leased on application, with lease being awarded to first qualified applicant	10 years and "as long thereafter"	$1.00/acre/year	12-1/2%	2,560 acres (but within 6 mile square)	30 days after bid award
Wyoming	Noncompetitive (a) Application for unleased, open lands -- leased to first qualified applicant (b) Simultaneous filing system for leases terminating by surrender, expiration or cancellation, or whether 2 or more applications are in conflict -- leased to first qualified applicant	10 years and "as long thereafter"	$1.00/acre/year -- $2.00/acre/year after establishment of production	12-1/2%	1,280 acres	60 days after bid award

3. Indian Lands

The leasing system for Indian oil and gas development is in a state of transition. Historically, oil and gas development occurred under concession agreements. The terms of the agreements were determined by the standard lease form and regulations of the Bureau of Indian Affairs (BIA), which is responsible for administering Indian trust matters on behalf of the Secretary of the Interior. Since the 1970's, however, many tribes have rejected the standard lease approach in favor of alternative forms of contracts and profit sharing arrangements. BIA also is revising its regulations to expand tribal control and flexibility in negotiating oil and gas agreements.

There are certain statutory restrictions on the terms of Indian oil and gas agreements. Some of the key provisions include the following:

- In most instances, oil and gas contracts can be secured only after a competitive bidding process. The major exception is that tribes organized under the Indian Reorganization Act have the discretion to use whatever methods their tribe authorized in its Constitution. Also, non-Indian Reorganization Act tribes may negotiate agreements after certain competitive bidding procedures have been satisfied.

- Indian oil and gas agreements must be co-signed by both the Indian owner and the Secretary of the Interior or his designate (i.e., the Director of BIA).

- The primary term of Indian oil and gas contracts cannot exceed 10 years.

- Oil and gas operations must comply with rules and regulations prescribed by the Secretary of the Interior.

Certain statutes prescribe special procedures for individual Indian lands and for certain reservations. The tribes covered by unique leasing laws include the Osage Nation, the Five Civilized Tribes of Oklahoma, the Crow Tribe, and the Shoshone Tribe of the Wind River Reservation.

D. Lease Stipulations

1. Federal Lease Stipulations

A review of standard and special stipulations applied before the lease is issued reveals that basically two types are used: site- or resource-specific, and all-encompassing.

The site- or resource-specific stipulation is developed to define or restrict surface use in a particular area or during a particular season. The value of the stipulation in balancing environmental protection and development, depends upon the quality

of information supporting it. Where a specific analysis has been properly prepared in a timely manner, the result can be an effective tool for lease development for both the agency and the lessor.

The all-encompassing stipulation was the type most often applied as standard for all leases offered in a state. The stipulation describes an agency's environmental protection authorities in vague terms. This type of stipulation is the most onerous in planning for compliance requirements, both for the agency and the operator. Opponents of development can use this type of stipulation to require numerous reports and assessments, resulting in additional special stipulations that may prohibit surface occupancy or delay development until the operator abandons the project. An agency staff can use the same approach to avoid making a decision on the project, especially in sensitive areas.

a. Leasing with Stipulations Derived from Forest Service Plans and BLM Plans

The most obvious and direct impact of land-use planning on an oil and gas lessee involves the BLM's procedure for selecting lease stipulations or rejecting lease offers. In addition to the general "open ended" standard stipulations used in all leases, other special lease stipulations are established by BLM. Other stipulations are selected by the agency charged with administering the lease tract and are incorporated in the lease with the concurrence of the Conservation Division of USGS. The stipulations range from minimal reclamation requirements to a prohibition of surface occupancy. Stipulations that completely prohibit surface occupancy have been characterized as inconsistent with the Mineral Leasing Act.[33] The United States District Court of Wyoming accepted this position with regard to wilderness study area stipulations and entered an order invalidating such stipulations in certain leases.[34] Most lease stipulations, however, will not fall within the rationale of that case.

To the extent that the Forest Service controls access to or use of the surface by oil and gas lessees, lease stipulations or action on lease offers on Forest Service lands are dictated by the National Environmental Policy Act of 1970 (NEPA) and the conformity requirements of Forest Service Resources Planning Act regulations. The Forest Service performs more extensive environmental analyses than BLM -- an EIS may be prepared on a single lease or an Application for Permit to Drill (APD). Before implementation of the Resources Planning Act, oil and gas development was rarely discussed in unit plans. Instead, it was treated in forest or multi-forest oil and gas EISs. Today, if a Forest Plan does not contain any references to possible impacts of oil and gas or if a Forest Plan is not in effect and the applicable oil and gas EIS or unit plan does not sufficiently deal with surface resources as they conflict with mineral development, the Forest Service has a statutory obligation to delay acting upon lease applications, pending completion of an adequate environmental analysis.

The environmental analysis provides the basis for special lease stipulations, terms, or conditions imposed by BLM at Forest Service request. It can be the basis for a recommendation against issuance of the lease by a regional forester. BLM usually honors such recommendations. The specific statutory obligations and extensive data requirements of the Forest Service have often delayed completion of such an analysis. Substantial delays in reviewing lease applications have been reported at the present time. These delays may be due in part to the fact that each lease is reviewed by the regional BLM office or, in the case of special lands including wilderness, reviewed personally by the BLM Director.

The imposition of allegedly unwarranted stipulations and the rejection of lease offers has engendered numerous appeals to the Interior Board of Land Appeals (IBLA). Appeal from BLM action on a lease application follows the appeal procedures of DOI. Appeal from Forest Service action on a lease application may follow Forest Service appeal procedures or DOI procedures. While the substance of BLM and Forest Service appeals does not differ noticeably, the BLM appeals differ procedurally from those of the Forest Service because of the existence of IBLA. The IBLA opinions provide the bulk of administrative precedent in oil and gas matters because the Forest Service has no similar decision-reporting system and because, given a choice, most appellants choose to appeal to DOI.

Generally, a BLM decision not to lease, or to lease with restrictive terms, is upheld if the administrative record supports the decision.[35] If the record does not support the stipulations or lease offer rejection, however, or if unresolved questions about the propriety of the same remain, the matter will be remanded to the BLM for further review to determine if a lease can be issued or a stipulation may be avoided.

The above discussion points out the need to ensure that Forest Plans, MFPs, oil and gas EISs, or umbrella Environmental Assessment Reports are accurate when they are prepared, and that they are frequently updated. The Forest Service land-use plans are by statute much more comprehensive than the BLM RMPs, but both the Forest Service and BLM are prohibited from deviating from those plans.

b. Drilling Operations and Stipulations

The selection of terms and conditions for a pre-drilling operations plan is similar to the process for selection of lease stipulations. Upon receipt of a map depicting a proposed drilling site, BLM reviews the applicable MFP or RMP to determine if conditions or stipulations must be imposed to prevent surface disturbance attendant to proposed surveying and staking. USGS and BLM must concur before such stipulations will be imposed.[36] Whether conditions are imposed in the initial preliminary environmental review, BLM must also review an operator's "multipoint surface use and operations plan" to ensure environmental protection and conformity with the existing MFP or RMP.

Like BLM, the Forest Service has a "cooperative agreement" with USGS.[37] The Forest Service agrees to perform necessary environmental reviews and provide the data to USGS for use in environmental analyses on drilling and production. Such environmental assessments must conform to the land use plans. The Forest Service is also to provide the necessary environmental protection requirements, which USGS then imposes and enforces.

c. Off-Lease Activities

Many off-lease activities are also affected by the land-use planning process. Every off-lease agency action of any consequence (e.g., the granting of a pipeline right-of-way) requires an RMP or MFP amendment to make the plan conform with the proposed action in the case of BLM, and with the Forest Plan in the case of the Forest Service.

2. State Lease Stipulations

Each state has its own methods for developing and enforcing lease stipulations. As with federal leases, state lease stipulations derive their authority primarily from state environmental protection laws, and leases must comply with all the requirements and rules of the state lands department. Many states attach special stipulations to oil and gas leases where unusual circumstances require it. For example, there are some areas in Wyoming where the Game and Fish Commission requires that operations be restricted or prohibited during certain times of the year -- such as during breeding or migrating seasons. These stipulations are made on a case-by-case basis, however, and are not standard practice.

Some states simply require that lessees comply with all state laws and regulations and have no specific environmental stipulations or requirements on their oil and gas leases. Many states incorporate a paragraph in the lease contract itself to take care of environmental concerns; others conduct a review of each lease application by the environmental division of the state lands department.

At the time when a lease sale is announced, a list of lease stipulations is posted with the sale list. Thus, before leasing a tract, each lessee is aware of the extent of development expenses he may encounter and can plan his development and activities around these requirements with a minimum of delay.

3. Indian Lease Stipulations

Stipulations on Indian oil and gas agreements vary among tribes and among individual owners. When negotiating an oil and gas contract, an Indian tribe may include stipulations regarding the employment and training of tribal members, profit sharing, accounting, environmental protection, and other matters. Oil and gas agreements on Indian lands require compliance with applicable tribal ordinances or regulations.

E. Delays Resulting From Current Leasing Policies and Programs

Land management policies currently in effect are a fundamental factor in leasing activities. The uncertainty, delay, and cumulative restrictions make leasing on federal acreage more costly than leasing on state or fee lands. These additional costs are especially burdensome to smaller operators, who are less able to pay them.

Leases in environmentally sensitive areas often include "no-surface occupancy" stipulations, making surface access to the leasehold impossible. The government on the one hand requires payment on lease rentals, while on the other it prohibits access and contractual lease rights. Independent operators drill the majority of wildcat wells and cannot afford the economic burden of holding leases that have no surface access rights.

In fiscal year 1979, BLM issued 11,758 onshore oil and gas leases. About half of those leases, 5,961, were issued in Colorado, Mississippi, New Mexico, Nevada, and Wyoming. Of these leases, 1,862 were over-the-counter, 3,896 were simultaneous, and 203 were competitive. About two-thirds, or 3,992 leases, were issued within 4 months of filing. The over-the-counter lease applications involve essentially new areas of "wildcat" interest. Of these leases, only 16 percent were issued within four months, compared to about 90 percent of the simultaneous and competitive leases being issued in the four-month time frame. The main reason for this difference is that over-the-counter lease applications have to go through procedures to determine that the land can actually be leased, while land leased under simultaneous or competitive bids has already undergone such analysis.[38]

The GAO study reviewed the types of delay encountered in oil and gas leasing in the five states mentioned above. The delays are divided into two categories:

- Delays attributable to federal leasing agencies

- BLM lease processing	453 cases
- Environmental analyses	153 cases
- Deferral of leasing in wilderness study areas	95 cases
- Title work	49 cases
- Other	34 cases
	784 cases

- Delays attributable to non-federal agency activities

- Appeals and litigation	54 cases

-	Applicant inaction	16 cases
-	Other (non-federal)	14 cases
		84 cases

Of the 784 federal agency cases, BLM was involved in 602 cases, the Forest Service in 134, and the Department of Defense in 42.

Using BLM's four-month average for processing leases, GAO concluded that major delays have occurred in the five states studied. Extrapolating their findings to total leases pending in the five review states, GAO estimates that 3,484 applications out of 3,995 would be delayed due to federal actions (87 percent of the lease applications).

The NPC is concerned that leasing delays:

- Prevent or hinder the assembling of lands into viable units for exploration and development
- Increase the costs of holding leased lands while a unit is being assembled
- Result in a variety of termination dates for leases in a unit that will reduce the time actually available for drilling.

In an effort to streamline the leasing and bidding processes, there must be unification and consolidation of the federal regulatory procedures as they relate to onshore leasing. It is most important that the entire process be simplified.

III. Onshore Permitting

A. The National Environmental Policy Act USGS Permit Review

NEPA requires all federal agencies to incorporate appropriate and careful consideration of the environmental effects of proposed actions into the agency decision-making process and to avoid or minimize the adverse effects of proposed actions to the fullest extent practicable. The EIS requirement under Section 102 serves as the most significant mechanism for implementing NEPA. Since USGS approval of leasehold activities, such as seismic studies, exploratory drilling, and production of oil and gas, constitutes a federal action, USGS is required to assess potential environmental effects prior to granting approval.

The Notice to Lessees and Operator No. 6 Approval of Operations (NTL-6) is a permit program designed by USGS to comply with NEPA requirements. Its objective is to assure that operations on oil and gas leases under USGS jurisdiction are conducted with due regard for environmental protection as well as to evaluate the environmental impacts of proposed operations via the required EIS process.

NTL-6 was issued on June 1, 1976. Since that time, the permitting process has steadily become more complex, and time requirements for approvals have lengthened considerably. This section examines the NTL-6 program requirements and reviews the procedures for USGS's recently implemented Categorical Exclusion Review (CER) process.

The basic requirement of the NTL-6 program is the inclusion of an appropriate surface-use plan with applications for leasehold operations or construction activities. The surface-use plan should be prepared with sufficient technical detail regarding the magnitude of surface disturbance and proposed rehabilitation procedures. The major involvement of this surface-use plan is in accompaniment with APD for the drilling of individual exploratory or development wells.

Although USGS is the designated lead agency for oil and gas developments on federal lands, other federal surface management agencies, including BLM, the Forest Service, and the BIA, are involved with the NTL-6 permit process because of various cooperative agreements or Interior Secretary Orders. Typically, USGS defers approval of APD until consent is given by the appropriate surface management agency. This consent is usually in the form of surface stipulations attached as conditions of approval to an APD. The surface management agency is responsible for establishing rehabilitation requirements.

NTL-6 instructs operators to file applications and surface-use plans at least 30 days in advance of contemplated starting dates for construction and indicates that applications will be processed as quickly as possible. However, no guarantee is given that approval will be granted after 30 days.

1. APD Requirements

a. Preliminary Environmental Review

The first step in the process is the filing of a Preliminary Environmental Review (PER) request by the operator, which consists of a map of the proposed locations, showing general topographic features and other information such as access roads and water sources. The surface management agency uses the PER map to review available information to determine if conflicts with other resource values may exist. If conflicts exist, a meeting is scheduled to resolve problem areas. Unless the operator is notified by USGS or the surface management agency that resource conflicts exist, a 15-day limit is given for this process step, after which the operator may proceed with survey staking and other field work.

b. APD and Surface-Use Plan

After approval of the PER, an operator generally conducts survey staking and cultural resource inventory work. An APD package is then prepared in accordance with NTL-6 instructions. For the APD portion of the package, detailed information is required regarding surveyed location and elevation; engineering data (casing

and cementing programs, mud programs); geological factors (surface and major geologic formations, zones of water, hydrocarbons or other minerals, logging programs); and other operating standards (BOP equipment, auxiliary and safety equipment, anticipated start and completion dates).

The requirements for the surface-use plan are also specified by NTL-6. The plan must provide for adequate protection of surface resources and other environmental components, and include measures for rehabilitation of disturbed lands.

c. Joint Onsite Inspection

After submittal of the APD package, including the surface-use plan, an onsite inspection is normally held. Attendees include representatives from USGS, the surface management agency, the operator, and the operator's earth-moving contractor. The purpose of the inspection is to select the most feasible and environmentally acceptable well sites, access roads, and other surface-use considerations.

d. Environmental Analysis

After completion of the onsite inspection, USGS prepares an environmental analysis or assessment (EA), which evaluates potential environmental effects and identifies mitigating measures. The EA is also used to determine whether approval of the proposed activities constitutes a major federal action significantly affecting the environment. Surface protection and rehabilitation stipulations furnished by the surface management agency are included in the EA.

e. Permit Approval

Approval of the application is granted, contingent on the terms and conditions attached to the APD, after completion of this process, provided that the EA is approved and it is determined that no formal EIS is required, consent of the surface management agency is given, and other factors are in order (bonding, designation of operator, state spacing regulations, and private surface owner agreement). However, several other factors may constrain approval, even though they are not specifically associated with the APD process, including access road rights-of-way, water permits, or other state or county permits.

2. Categorical Exclusion Review

The CER procedures were developed by USGS to alleviate the extensive manpower and paperwork requirements associated with preparation of an EA for every proposed well. The procedures provide that a well can be excluded from the EA requirement, provided that nine criteria regarding environmental, archaeological, safety, and sociological factors are satisfied. The CER exclusion applies to the first well drilled on a lease or in a development area. The second ("confirmation") well, however, requires an EA. This EA

would address the environmental effects and mitigating measures associated with the second well, based on information in the APD package and surface-use plan. The EA would also address expected cumulative impacts associated with full field development. Thus, the EA becomes a kind of "umbrella" EA, after which other proposed field development wells can be excluded from the EA requirement, again provided the nine criteria are met. Complete APD packages, with the surface-use plans, are still required.

3. Delays Resulting from NTL-6 Review

Because of the number of discrete steps and the various agencies and individuals associated with the NTL-6 permit process, multiple delay factors frequently are experienced by operators seeking approval of applications. Since several ancillary laws and regulations, other than NEPA, are interrelated with NTL-6, the permit process has become increasingly complex. Serious, disruptive delays are experienced by industry. Drilling programs cannot be scheduled with any assurance that permits can be obtained without delays. Length of time required to obtain normal APD approval has increased from an estimated 15 days in 1976, prior to NTL-6, to a general range of 80 to 100 days in 1980. Longer time periods for permit approval (200 days or more) are not uncommon. In spite of the new CER procedures, the lengthy permit approval period is expected to increase in the future because of the complexity of the permit process and number of potential delay factors.

Average permit costs have risen from approximately $750 in 1976, prior to NTL-6, to a range of $1,500 to $3,000 in 1980. Unidentified or intangible costs, however, are associated with standby charges for an inactive drill rig or the release of a rig because no permits are approved. With the current great demand for drilling rigs in the Rocky Mountain regions, these latter occurrences are increasing in frequency and add a significant dimension to the problems of permit delays associated with NTL-6.

B. Federal Land Policy and Management Act Review

FLPMA established a planning system for government lands and resources, including oil and gas, that further defined BLM's (and to a lesser extent, the Forest Service's) responsibilities for surface management. The result of this legislation and subsequent regulation on oil and gas development has been profound. While a majority of the FLPMA requirements are warranted and have resulted in tangible benefits to the environment, the manner of implementation has caused delays in the permitting of oil and gas activities on federal lands.

The review and designation of right-of-way corridors pursuant to Section 503 of FLPMA is a planning provision of FLPMA that may impact oil and gas operators. It applies both to the Secretary of the Interior and to the Secretary of Agriculture. The location of rights-of-way for oil or gas pipelines, off-lease collection facilities, access roads, electric transmission lines, water pipelines, and other purposes may be affected under this section. To date,

no right-of-way corridors have been formally designed under this authority. Regulations promulgated on July 1, 1980, however, define the criteria for designation of such right-of-way corridors, and BLM and the Forest Service are according corridor designation a high priority.

Designation of a corridor may be initiated by BLM or the Forest Service, or by receipt of an application for designation. Corridors shall be designated, to the extent practical, consistent with land-use plans. Once a corridor is designated pursuant to Section 503, BLM is directed to confine new right-of-way grants to that corridor to the extent practical. In some instances it may be possible for oil and gas operators to show that it is not practical to locate new rights-of-way through designated corridors.

FLPMA has had a major effect on the transportation segment of oil and gas development with regard to right-of-way requirements for gas gathering and distribution lines. Along with typical requirements for archaeological clearance and other environmental checks, operators are required to submit detailed corporate information files, survey plats, and other information. Processing by BLM commonly results in six months or more delay in hooking up completed wells to collection systems. In extreme cases, such delays are for 500 feet or less of pipeline. Some state offices, notably Utah, are currently experimenting with procedures to eliminate the right-of-way processing delays by inclusion of the grant in the APD approval.

C. Endangered Species Act Review

The Endangered Species Act of 1973, as amended, declares a federal policy to seek the conservation of endangered species and threatened species. Conservation, as defined by the Act, means "the use of all methods and procedures that are necessary to bring any endangered species or threatened species to the point at which the measures provided pursuant to this Act are no longer necessary"; that is, recovery of the population of the threatened or endangered species to such a degree as to warrant removal from the threatened or endangered category.

Although the Departments of Commerce and Agriculture, through designations of the respective Secretaries, are involved with implementations of the endangered species program, DOI is mainly responsible for carrying out the program through FWS. Under the sponsorship of FWS, species are listed, critical habitats determined, conservation programs established, and federal agency actions reviewed.

Three definitions important in discussing the implementation of the Act are given below.

- Endangered Species: any species in danger of extinction throughout all or a significant portion of its range. Insect species that constitute a pest with overriding or overwhelming risks to man are excluded. All other fish and

wildlife, however, including vertebrate and invertebrate species as well as any plant species, can be given the protection of the law if designated as endangered or threatened.

- Threatened Species: any species likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.

- Critical Habitat: specific area within the geographic area occupied by the species on which are found those physical or biological features essential to the conservation of the species and that may require special management considerations or protection. Critical habitat does not include the entire geographic area that can be occupied by the threatened or endangered species.

All federal agencies are charged with the responsibility of furthering the purposes of the Act through Section 7. This section requires each agency, through consultations with FWS, to ensure that any action authorized, funded, or carried out by the agency will not jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of critical habitat.

Because of the strength of the law and the number and prevalence of officially listed species, conflicts can arise between the endangered or threatened species and other resources located in the vicinity of the habitat or known occurrence of the endangered or threatened species. Since the protective covenants contained in the law clearly provide for endangered or threatened species protection in the event a proposed action would place the subject species in jeopardy, results of any consultation typically favor the subject species or habitat. A proposed action may be allowed to proceed after consultation, but generally under restrictive conditions of approval, modified plans, and a relatively lengthy time period.

Unfortunately, the nature of the oil and gas industry, which generally requires relatively quick turnaround times for permits in order to assure logical scheduling of drilling activities, does not easily match the time frames utilized in the Section 7 consultation process. Operators may withdraw applications rather than struggle with the regulatory requirements of the Act. Since no practical exemption exists within the framework of the law, no effective means to accelerate or bypass the process exists.

LAND -- OFFSHORE

I. Overview -- Access and Development

The extensive search for offshore oil and gas began in the late 1940's and early 1950's on state-owned lands. In 1954, the first lease sale was held in federal offshore waters; 54 other federal

offshore lease sales had been held by early 1981. Yet only a small part of federal offshore lands has been leased to date. The areas that have been leased, explored, and placed into production provide an essential part of our domestic energy. From 1954 through 1980, more than 5 billion barrels of crude oil and condensate and nearly 50 TCF of natural gas have been produced from offshore wells in the federal domain.[39]

In 1980, federal offshore lands accounted for more than 9 percent of U.S. crude oil and condensate production and 23 percent of domestic natural gas production.[40] Most of the income generated from the sale of this oil and gas has gone to the federal government. Over the years, the energy industries have paid almost $41 billion to the federal government in lease bonus money, rental fees, and royalty payments. Even before taxes, that amount represents 65 percent of the value of all of the oil and gas produced from those leases through 1980.[41]

Government policies on access to and regulation of offshore areas have increased the investment risk and significantly slowed development. Many lease sales have been scheduled only to be delayed and, in some cases, cancelled by federal agencies. As a result of these actions, some of the most promising offshore areas have never been opened to exploration. Other areas have been opened on a limited basis only. Ninety-five percent of the offshore acreage remains unexplored. Some of the unleased areas rank high as prospective candidates for commercial oil and gas discoveries.[42]

This section examines the key legislative and administrative issues facing offshore oil and gas exploration and development. The applicable laws discussed are the Outer Continental Shelf Lands Act (OCSLA) Amendments of 1978; the Coastal Zone Management Act of 1972 (CZMA); and the Marine Protection, Research and Sanctuaries Act of 1972. Also, an extensive discussion of the Five-Year OCS Oil and Gas Leasing Schedule is included.

II. Outer Continental Shelf Lands Act Amendments of 1978

The OCSLA was enacted in 1953. It asserted federal jurisdiction over the OCS to a water depth of 200 meters and recognized DOI as the agency to administer and regulate oil, gas, sulfur, and other mineral operations on the OCS. The Act also authorized such rules and regulations as the Secretary of the Interior determined to be necessary in providing for the prevention of waste, conservation of natural resources, and protection of correlative rights.

A number of environmentally oriented laws have been enacted by Congress since the OCSLA that have changed the pattern of offshore operations significantly, including NEPA, CZMA, the Marine Protection, Research and Sanctuaries Act, and the amendments to the Clean Air Act and the Clean Water Act. The major legislative development concerning offshore operations in the last decade, however, was the passage of the 1978 amendments to the OCSLA. The stated purposes

of the OCSLA Amendments of 1978 include: establishing policies and procedures for managing OCS oil and gas resources to expedite exploration and development; providing greater state and local governmental input into OCS decision-making; minimizing risk of damage to human, marine, and coastal environments; establishing an oil spill liability fund to pay for prompt removal of spilled or discharged oil; and establishing a fisherman's contingency fund to pay for damages to commercial fishing vessels or gear due to OCS activities.

The provisions of this Act have delayed and restricted OCS operations in the following ways:

- Increased the number of agencies authorized to regulate certain OCS activities
- Required the Secretary of the Interior to consider state Coastal Zone Management (CZM) plans in developing five-year leasing schedules
- Provided for greater coastal state participation in the leasing decision process
- Mandated certain environmental impact studies
- Provided for citizen suits
- Compelled the use of alternative bidding systems
- Required the promulgation and implementation of some 40 new or revised regulations of offshore exploration and production operations.

Permitting and licensing of OCS activities became much more complicated and, therefore, more time-consuming and expensive. In 1981, GAO estimated that the time required for the processing of exploration plans and development plans rose to an average of 119 days and 206 days, respectively, as compared to 30 days for each before 1978.[43]

III. The Five-Year OCS Oil and Gas Leasing Schedule

The Five-Year OCS Oil and Gas Leasing Schedule may be the most important procedural element in the OCS process, as it represents the nation's commitment toward exploration and development on the OCS. Despite this importance, the five-year schedule is but one of many elements in the total OCS process. A basic understanding of the total process is thus a desirable and necessary prelude to a more detailed discussion of the five-year schedule. The early portion of this section, therefore, has been devoted to a brief history of the five-year schedule followed by a description of government's role in the OCS and the administrative steps and processes attendant to exploration and development of the OCS.

A. Discussion of the Five-Year OCS Oil and Gas Leasing Schedule

1. History

The OCSLA of 1953 authorized the Secretary of the Interior to lease federal OCS lands for oil and gas development. During the early years from 1954 through 1969, OCS development was noncontroversial and there was no formal leasing schedule. An expression of interest by industry for new lease sales and the U.S. Bureau of Budget's requirements heavily influenced the leasing process. During the late 1960's, BLM undertook studies to determine the appropriate timing of lease sales. In the 1970's, environmental emphasis was made part of the lease sale planning process. In June 1971, DOI published its first lease schedule, covering a four-and-a-half-year time frame. Additional schedules were published through 1977 with a four-year schedule in November 1974 representing a change of focus in the leasing program with its emphasis on the frontier areas. The 1977 lease schedule was the first schedule to provide a time period for state government comment on the pre-lease planning process.

The evolution of the leasing program culminated with the OCSLA Amendments of 1978, which required the development of a five-year leasing schedule and mandated that state and local governments be included in the OCS decision-making process. In June 1979, a proposed five-year schedule was submitted to Congress and state governments for review and comments. Following a year of review, a final five-year schedule was published in June 1980 (Table 21).

A new, comprehensive schedule was proposed by the Secretary of the Interior in April 1981 (Table 22). This proposed schedule must undergo the same approval process as the prior schedules. Thereafter, the Secretary is required to review the schedule annually and must obtain Congressional and state review of all proposed changes.

2. Importance of the Schedule

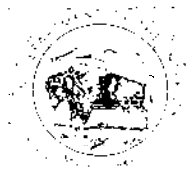
The five-year leasing schedule represents a commitment by government to open designated areas in the OCS to exploration for oil and gas resources. The schedule provides the planning tool needed by government and industry to create an orderly process and to allocate technical and financial resources.

The schedule is important to government as a planning mechanism from which programs may be developed to perform the necessary administrative actions leading to each individual sale. The individual administrative steps accompanying a sale are discussed in the following sections. The five-year schedule also provides a priority schedule for the BLM Environmental Studies Program. By utilizing this schedule, field data and scientific studies may be acquired in a timely manner to have data available for the preparation of the environmental statement for each sale.

TABLE 21

Final Five-Year OCS Oil and Gas Leasing Schedule -- June 1980

PROPOSED SALE AREA	PROPOSED DATE	1980 (J F M A M J J A S O N D)	1981 (J F M A M J J A S O N D)	1982 (J F M A M J J A S O N D)	1983 (J F M A M J J A S O N D)	1984 (J F M A M J J A S O N D)	1985 (J F M A M J J A S O N D)
A62 Gulf of Mexico	9/80	F P Sc R N S					
55 Gulf of Alaska	10/80	F P Sc R N S					
62 Gulf of Mexico	11 80	F P Sc R N S					
53 Central N. Calif.	5/81	E H F P	Sc R N S				
RS-1 Reoffering Sale	6 81		P Sc R N S				
A66 Gulf of Mexico	7 81	E H F	P Sc R N S				
56 South Atlantic	8/81	E H	F P Sc R N S				
60 Cook Inlet	9/81	E H	F P Sc R N S				
66 Gulf of Mexico	10/81	E H F	P Sc R N S				
59 Mid-Atlantic	12/81	E	H F P Sc R N S				
67 Gulf of Mexico	3/82	C D T	E H F P Sc	R N S			
RS-2 Reoffering Sale	6/82			P Sc R N S			
68 Southern California	6/82	D T	E H F	P Sc R N S			
69 Gulf of Mexico	8 '82	C D T	E H F	P Sc R N S			
57 Norton Basin	9/82	T	H	F P Sc R N S			
52 North Atlantic	10/82	D T	E H	F P Sc R N S			
70 St. George Basin	12/82	T	E	H F P Sc R N S			
71 Beaufort Sea	2/83	T	E	H F P Sc R	N S		
72 Gulf of Mexico	3/83		C D T	E H F P Sc	R N S		
61 Kodiak	4/83	C D	T	E H F P	Sc R N S		
73 California	5/83	C	D T	E H F P	Sc R N S		
RS-3 Reoffering Sale	6 83				P Sc R N S		
74 Gulf of Mexico	9 83		C D T	E H F	P Sc R N S		
75 No. Aleutian Shelf	10/83	C D T		E H	F P Sc R N S		
76 Mid-Atlantic	11/83		C D T	E H	F P Sc R N S		
78 South Atlantic	1/84		C D T	E	H F P Sc R N	S	
79 Gulf of Mexico	3 84			C D T	E H F P Sc	R N S	
RS-4 Reoffering Sale	5/84					P Sc R N S	
80 California	6/84		C D	T	E H F	P Sc R N S	
81 Gulf of Mexico	7/84			C D T	E H F	P Sc R N S	
82 North Atlantic	10 84			C D T	E H	F P Sc R N S	
83 Navarin Basin	12 84		C D	T	E	H F P Sc R N S	
84 Gulf of Mexico	1 85			C	D T	E H F P Sc R N	S
☆85 Chukchi Sea	2 85		C D	T	E	H F P Sc R	N S
86 Hope Basin	5 85		C D	T		E H F P	Sc R N S
RS-5 Reoffering Sale	6 85						P Sc R N S



Secretary of the Interior

C Call For Nominations
D Nominations Due
T Tentative Tract Selection
E Draft Environmental Statement
H Public Hearing
F Final Environmental Statement
P Proposed Notice of Sale
S_c State Comments Due
R Energy Review
N Notice of Sale
S Sale

☆The holding of the Chukchi Sale at this time is contingent upon a reasonable assumption that technology will be available for exploration and development of the tracts included in the sale.

SOURCE: U.S. Department of the Interior.

TABLE 22

Draft Proposed Five-Year OCS Oil and Gas Leasing Schedule -- April 1981

SALE AREA	Proposed Date	1982	1983	1984	1985	1986
67 Gulf of Mexico	2/82	N S				
68 S. California	4/82	G R N S				
57 Norton Basin	5/82	F P G R N S				
RS-2	6/82	P G R N S				
52 North Atlantic	8/82	F P G R N S				
71 Diapir Field	10/82	E H F P G R N S				
69 Gulf of Mexico	11/82	P G R N S				
70 St. George Basin	12/82	H F P G R N S				
73 California	1/83	E H F P G R N	S			
76 Mid Atlantic	2/83	E H F P G R	N S			
75 N. Aleutian Basin	4/83	E H F P	G R N S			
72 Gulf of Mexico	5/83	E H	F P G R N S			
RS-3	6/83		P G R N S			
78 So. Atlantic	7/83	E H	F P G R N S			
74 Gulf of Mexico	11/83	E H	F P G R N S			
83 Navarin Basin	12/83	C D A	E H F P G R N S			
80 California	1/84	C D	E H F P G R N	S		
82 N. Atlantic	2/84	C D A	E H F P G R	N S		
87 Diapir Field	3/84	C D A	E H F P	G R N S		
79 Gulf of Mexico	4/84	C D A	E H F P	G R N S		
88 Norton Basin	6/84	C D	A E H	F P G R N S		
RS-4	7/84			P G R N S		
89 St George Basin	10/84		C D A	E H F P G R N S		
81 Gulf of Mexico	11/84	C D A	E H F	P G R N S		
85 Barrow Arch	1/85		C D A	E H F P G R N	S	
90 Atlantic	2/85		C D A	E H F P G R	N S	
91 California	3/85		C D A	E H F P	G R N S	
84 Gulf of Mexico	4/85		C D	E H F P	G R N S	
RS-5	5/85				P G R N S	
92 N. Aleutian Basin	6/85		C D	A E H	F P G R N S	
86 Hope Basin	7/85		C D	A E H	F P G R N S	
93 St. Matthew-Hall	10/85			C D A	E H F P G R N S	
94 Gulf of Mexico	11/85		C D A	E H F	P G R N S	
95 California	1/86			C D A	E H F P G R N	S
96 Atlantic	2/86			C D A	E H F P G R	N S
97 Diapir Field	3/86			C D A	E H	G R N S
98 Gulf of Mexico	4/86			C D A	E H F P	G R N S
RS-6	5/86					P G R N S
99 Norton Basin	6/86			C D	A E H	F P G R N S
100 S. Alaska *	8/86			C	D A E	H F P G R N S
101 St. George Basin	10/86				C D A	E H F P G R N S
102 Gulf of Mexico	11/86			C D A	E H F	P G R N S

C - Call for Information
D - Information Due
A - Area Selection
E - Draft Environmental Impact Statement
H - Public Hearing
F - Final Environmental Impact Statement
P - Proposed Notice of Sale
G - Governors' Comments Due
R - DOE Review
N - Notice of Sale
S - Sale

* includes Cook Inlet, Shumagin, Kodiak, Gulf of Alaska

SOURCE: U.S. Department of the Interior.

The five-year leasing schedule serves as a basis for industry planning by OCS operators, service industries, drilling contractors, and other suppliers and support industries. The schedule is exceptionally crucial in governing the timing of collection of

geophysical and geological data necessary for operators to prepare for each sale Geophysical interpretations, particularly in frontier areas, are the basis for locating structures of interest and for determining bids to be made on individual tracts when a sale occurs. Collection of seismic data to make these interpretations must often be commenced several years before the area is to be offered for sale to allow sufficient time for study and interpretation.

During the preparation of the five-year leasing schedule, states, local communities, and other interested parties are afforded an opportunity to comment on the schedule, particularly on how sales may affect the state or community. This process may often cause changes in the schedule to accommodate state, regional, or local concerns. The final approved five-year schedule provides a useful mechanism to the states and local communities from which they may give consideration to creation of infrastructure necessary to support the anticipated OCS activity, the most desirable location of onshore and support facilities, and the interfaces that state and local governments wish to have with the industry activity.

The five-year schedule also provides other groups the opportunity to anticipate timing of OCS operations that may affect their interests. The schedule is of particular interest to environmental groups, which have frequently challenged the ordering of sales with respect to the availability of scientific data on the potential adverse impacts on biological communities resulting from exploration and development activities.

B. The Role of Government in the OCS

The federal government serves as the manager of the OCS resource The government has authority over which of the OCS resources will be offered for exploration and development, and the time frame in which they will be offered; the conditions under which industry will be allowed to explore and develop these resources, including bonuses to be paid for the opportunity to explore and develop and royalties to be paid to the federal government if production is obtained; and the rules under which operations will be conducted, taking into account environmental concerns and potential conflicts with other ocean industries such as fishing and shipping.

In carrying out these and other functions, as many as 18 federal agencies have an active interest in some aspects of OCS operations and occasionally participate in the shaping of proposed actions. Of these, six agencies have statutory authorities that require them to regulate day-to-day operations on the OCS: the Department of the Interior's Bureau of Land Management and Geological Survey; the Department of Transportation's (DOT) U.S. Coast Guard and Materials Transportation Bureau/Office of Pipeline Safety; the Environmental Protection Agency; and the Department of Defense (U.S. Army Corps of Engineers). The role of these agencies in OCS development activities is discussed in more detail below.

1. Department of the Interior

DOI has general responsibility for managing mineral leasing on the OCS, including coordination of federal activities. Within the Department, BLM and USGS are the two principal units with OCS regulatory responsibilities. The OCSLA of 1953 increased BLM's responsibilities by making it responsible for administering the leasing procedures for OCS tracts. Guided by the Act, BLM issues lease stipulations that set forth the terms guiding development and the constraints and procedures that are to be observed by operators. Lease stipulations also cover pipelines; however, BLM and USGS have concluded a memorandum of understanding (MOU) concerning the approval of OCS pipeline routes and construction. This MOU helps to clarify the roles of BLM and USGS relating to pipelines and is intended to minimize overlapping functions.

USGS issues regulations for oil and gas operations on the OCS. Regulations are proposed, written, implemented, and enforced by USGS to assure that operations under federal oil and gas leases and permits on the OCS emphasize the safety of operations, prevention of pollution, and protection of life and property, and that they minimize the risk of environmental damage.

2. Department of Transportation

The principal units in DOT with regulatory responsibilities for oil and gas on the OCS are the Coast Guard and the Office of Pipeline Safety Regulation in the Materials Transportation Bureau.

The Coast Guard's regulatory authority generally relates to its responsibility for maritime safety and for the safe operation of vessels and floating ocean structures. Under the OCSLA Amendments of 1978, the Coast Guard promulgates and enforces regulations to promote the safety of life and property on OCS facilities and vessels engaged in OCS activities.

The Natural Gas Pipeline Safety Act of 1968 established the Office of Pipeline Safety in DOT. This office develops standards and regulations to assure safe construction and operation of pipelines, including those on the OCS. Renamed the Office of Pipeline Safety Regulation, this unit of the federal government moved to the newly created Materials Transportation Bureau in 1977. The office has jurisdiction for gathering lines and transmission pipelines offshore and onshore, but pipelines of an oil- or gas-producing facility are under the jurisdiction of USGS from the platform to the flange connected to the gathering lines. The scope of responsibility is described by an MOU between DOT and DOI, but the agreement fails to clarify jurisdiction over a number of other types of pipelines, such as transmission pipelines mounted on and crossing over fixed offshore platforms.

3. Environmental Protection Agency

While EPA is responsible for regulating air quality on land, the OCSLA specifically charges USGS with regulating the air emissions of OCS installations. EPA's major authorities on the OCS are

those sections of the Clean Water Act of 1972 as amended that authorize the setting of effluent standards and ocean discharge criteria, and the issuing of discharge permits that reflect the standards and criteria.

4. Department of Defense

In accordance with OCS legislation, the Defense Department's U.S. Army Corps of Engineers occasionally has established shipping safety fairways and anchorages on the OCS to control the erection of structures in order to provide safe approach for vessels through areas of mineral exploration and development. However, the Ports and Waterways Safety Act of 1978 gave the Coast Guard the authority to establish, operate, and maintain routing systems and fairways. Nevertheless, the U.S. Army Corps of Engineers retains responsibility for shipping safety fairways and anchorage areas in the Gulf of Mexico and in the Pacific Ocean at Port Hueneme, California. The Corps have also established regulations that authorize drilling in the Gulf of Santa Catalina, California.

C. Lease Sales and Permitting

1. Individual Lease Sales

a. Call for Information

The OCS has been divided by coordinates into a system of blocks of three miles on each side containing 5,760 acres. In issuing calls for information, BLM identifies the overall area in which the sale is to be held. Such an area will include several hundred blocks of 5,760 acres each, depending upon the amount of acreage to be offered in the sale. Interested parties, primarily industry, will nominate to BLM those blocks that they prefer to be included in the forthcoming sale. Other groups such as public interest groups, the fishing industry, states, or other interested parties may also nominate tracts to be included or tracts that should be excluded from the sale area. Based on comments received and nominations made, either positive or negative, BLM then makes a preliminary decision as to which blocks will be included in the forthcoming sale.

b. Draft Environmental Impact Statement

The next step in the sale preparation process is to prepare an environmental review and to present that review in a document called the Draft Environmental Impact Statement (DEIS). The DEIS, prepared by BLM, reviews the projected environmental consequences of exploring and developing all of the tracts tentatively selected for sale as well as the alternatives to holding the sale.

c. Public Hearing

After publication of the DEIS, notice is given in the *Federal Register* to interested parties that a public hearing will be held

concerning the forthcoming sale. Such hearings are normally held near the offshore sale area. Any individual with an interest in the sale may request and obtain the opportunity to speak at the hearing. Such hearings are conducted before a panel of individuals from DOI and a full transcript of the hearing is made containing both oral remarks and written statements submitted to the panel.

d. Final Environmental Impact Statement

The Final Environmental Impact Statement (FEIS) is a modified version of the DEIS that takes into account oral and written comments received at the public hearing. The FEIS may delete certain tracts from the sale depending upon public comments received, and in its final form serves as the official document to satisfy NEPA requirements.

e. Proposed Notice of Sale

The proposed Notice of Sale sets forth the tracts proposed for inclusion in the forthcoming sale and the proposed conditions under which such tracts will be offered. Proposed conditions will include the bidding system to be utilized as well as stipulations regarding the conduct of operation on certain tracts in the sale area. The proposed notice elicits public comment as to these conditions in the sale area for consideration by the BLM in preparing the final Notice of Sale.

f. Notice of Sale

The Notice of Sale sets forth the date, time, and place that the sale will be held, the tracts to be offered in the sale, and the conditions under which such tracts will be offered.

g. Sale

The lease sale is conducted by the regional BLM manager responsible for the sale area. Companies or individuals submit sealed bids to BLM and such bids are opened and announced at the sale. The high bidder for each tract must submit a certified check amounting to 20 percent of his bid during the sale proceedings. The award of tracts must be made by BLM within 60 days following the sale. The high bidder is not automatically awarded the lease, because DOI may reject any bid as too low.

Offshore lease sales rely mainly on a bonus-bid/fixed-royalty format. This format requires significant sums of "up front money" (money needed immediately for payment of the bonus and first-year rental). The bonus assures the government of significant income from the lease, even if later exploration results in no commercial oil or natural gas discovery.

h. Lease Terms

In general, offshore primary lease terms are for a period of five years. Under certain conditions, a 10-year lease term is

authorized under the OCSLA Amendments of 1978 (for example, in some deepwater and frontier areas). Lease rights extend past the primary term for as long as commercial production continues.

2. The Permitting Process

a. Overview

Post-sale permits and other actions or filings required of the operator in order to proceed with exploration, production, and development are far too numerous to allow discussion on an individual basis. A partial listing of such requirements by each of the agencies with primary jurisdiction over OCS activity is shown below.

- U.S. Geological Survey
  - Plan of Exploration
  - Plan of Development
  - Plan of Production/Operation
  - Platform Permit Application
  - Platform Design Certification
  - Platform Completion Notice
  - Sundry Notice of Soil Borings
  - Annual Pipeline Inspection Report
  - Facilities Permit Application
  - Pipeline Permit Application
  - Suspension of Production
  - Leaseholder Determination
  - Drilling Permit
  - Workover Permit

- U.S. Army Corps of Engineers
  - Blanket Permits
  - Individual Permits
  - Notice of Rig Movement
  - Notice of Beginning Installation
  - Notice of Completion Installation
  - Annual Structure Report

- U.S. Coast Guard
  - Notice of Rig Movements
  - Notice of Establishing or Discontinuing Navigation Aid
  - Notice of Change in Navigation Aid Equipment
  - Notice of Change in Ownership of Structure

- U.S. Environmental Protection Agency
  - National Pollution Discharge Elimination System (NPDES) Permits.

b. Key Permitting Requirements

All of the foregoing permitting requirements are important and must be satisfied prior to commencing operations. However, some

processes are more difficult to satisfy and less predictable than others. These processes are described below.

(i) Plans of Exploration

The Plan of Exploration (POE) is filed with USGS and contains a description of the exploratory drilling activities the operator proposes to perform on each lease. In addition to all pertinent data concerning wells proposed to be drilled, the POE must be accompanied by an environmental report stating the probable consequences of the proposed exploratory activity. The POE is submitted to affected adjacent states that have approved CZM plans for their review as to the consistency of the proposed operations with the state's CZM plan. Although the USGS supervisor must approve or reject the plan within 30 days of receipt, the adjacent states have a period of 180 days to review the plan for consistency. Affected states may reject the plan as inconsistent with their CZM plan, or may request additional information through USGS at any juncture within the 180-day approval period.

(ii) Plans of Development

The Plan of Development (POD) serves the same purpose as the POE except that it concerns the development phase of OCS operations. The POD receives the same review from USGS and affected coastal states, but will tend, in general, to be more complex than the POE, as the magnitude and complexity of operations performed during development are much greater than during the exploration phase.

(iii) NPDES Permits

NPDES permits administered by EPA cover all intentional discharges from an operation in the OCS. During exploratory drilling, these discharges would include primarily sanitary sewage discharges and the discharge of drilling muds and cuttings. During producing operations, discharges would also include formation waters produced with the oil or gas. In filing for this discharge permit, the operator must state the volume of his expected discharges and must identify expected toxic substances contained in these discharges.

After processing the permit application, EPA normally issues a draft permit and invites comment from the affected operator and the public on the conditions of the permit. In frontier and sensitive areas, it has been common for EPA to require extensive monitoring programs and/or special biological studies as a condition for permit approval. In certain situations, permit approval may require a period of six months to one year or longer. The NPDES permit is also subject to an administrative procedure called "an evidentiary hearing," which may be requested by the operator or any other interested party. Evidentiary hearings will result if an interested party can show cause why the hearing is necessary. The scheduling of evidentiary hearings usually requires a period of many months and may result in denial of the permit, or at a minimum, a delay of one year or more in permit issuance.

EPA issued three general permits for Gulf of Mexico OCS operations in April 1981, in recognition of the needs for administrative simplification of the permitting process, the minimal impacts of the discharges, and the similarities of the operations in many different locations.

In September 1981 EPA published a draft general permit for OCS operations off Southern California.[44] EPA said that a review of the individual NPDES permits already issued under the Clean Water Act for the 15 exploratory drilling vessels and 12 production platforms in the affected area clearly indicated that these facilities would be more appropriately controlled by a single general permit, which is expected to be issued in early 1982.

EPA said that under a general permit, environmental monitoring can be defined and imposed on facilities operating in a permit area, thus reducing the cost per facility and providing the Agency with a better mechanism to address environmental degradation. EPA added that general permits eliminate, for the Agency, the time-consuming and resource-intensive process of reviewing and evaluating individual permit applications, and significantly reduce the regulatory burden imposed on industry in applying for and obtaining individual permits.

The facilities involved in the general permit are located where discharges will not significantly affect the marine environment. EPA stated that in view of the national effort to identify and develop the nation's natural resources, and in view of DOI's efforts to accelerate offshore oil and gas lease sales, it is particularly important that EPA expedite issuance of NPDES permits for these facilities. EPA commented that a general permit would be particularly appropriate for mobile drilling units, because it allows them to move efficienty from one location to another.

D. Environmental Considerations

1. The Final Environmental Impact Statement

The preparation and publication of the Five-Year OCS Oil and Gas Leasing Schedule has been viewed by DOI as a "major federal action" subject to the NEPA process. The FEIS for the March 1980-February 1985 five-year schedule was published by BLM in 1980. Although this document is considered necessary to satisfy legal and administrative processes, there are no environmental impacts in the OCS that result from the publication of the five-year schedule. As the schedule lacks specificity as to the location of tracts to be offered in individual sales, the potential environmental impacts for each sale area have, by necessity, been addressed in general terms.

In considering potential environmental consequences, the FEIS considers five generic impact-producing factors: oil spills, water effluents, air emissions, onshore facilities, and offshore facilities. These generic factors may impact on certain systems, activities, or other concerns, including the marine environment, coastal

ecosystems, water quality and supply, navigation, commercial fishing, endangered species, air quality, and socio-economic systems. The FEIS also treats in a similar manner a number of alternatives to the final five-year schedule that delete different sales from the schedule.

Accurate prediction of the environmental consequences of the five-year schedule is impossible, due to a lack of knowledge as to which tracts will be leased in a given sale area, where exploratory drilling will be conducted, whether discoveries will be made, whether such discoveries will be oil or gas, and the nature and location of any operational incidents attendant to the offshore operation. The FEIS assumes that exploration, development, and production will occur in all sale areas and that oil will be discovered and produced in volumes equal to the USGS resource estimate for the area. These assumptions are perhaps as good as any if it is presumed that the totality of all possible OCS activities must be addressed simultaneously in a single document. A simpler approach, which could eliminate much conjecture and generality, would be initially to limit consideration of environmental consequences to exploratory drilling activities and augment the FEIS with supplemental environmental statements for those areas in which marketable discoveries occur. This approach to streamline the EIS process is under consideration for the OCS leasing process.

2. Predictable Impacts of Exploratory Drilling on the OCS

a. Onshore Impacts

Onshore environmental impacts associated with exploratory drilling areas arise from the need for a temporary land base to support the offshore operation. These activities are principally related to stockpiling, loading, and transportation of equipment and supplies; the housing and care for associated employees; and the transport of offshore workers to and from offshore drilling rigs.

The nature and scope of these operations are well documented and the impacts are generally modest in populated coastal areas. The same operations conducted in unpopulated or sparsely populated areas may become more significant because of the lack of an established infrastructure.

b. Offshore Impacts

Offshore impacts result from the moving of drilling equipment to and from well sites, the conduct of the drilling operations, and the transport of supplies to and from the rigs. Areas of concern during exploratory drilling focus on possible conflicts with other ocean industries, principally fishing, and the environmental consequences from discharge of drilling muds and cuttings as well as the potential for oil spills. In frontier areas offshore Alaska, concerns also are raised relative to the effect of offshore drilling operations on a variety of sea animals, particularly the bowhead

whale, which is important to the subsistence of certain native groups. The NPC has addressed these concerns in its 1981 report, U.S. Arctic Oil and Gas.

The degree of impact by exploratory drilling operations on these areas of concern is controversial, viewed by some to be negligible, and by others to be potentially significant. The degree of concern is, however, substantially less than for development activities. The only known and predictable impacts are those resulting from the physical presence of drilling rigs and support vessels and the discharge of drilling muds, cuttings, and treated sanitary wastes into the ocean. The support vessels (two per rig) will cause some modest temporary increase in marine traffic, and a drilling rig will temporarily occupy approximately one acre. The impact of the temporary discharges should be modest, given that the number of wells drilled will be limited.

All other potential impacts from offshore operations are purely speculative. No oil spill exceeding 50 barrels has occurred in U.S. waters during exploratory drilling in the history of the OCS. Although there is no absolute assurance that a larger spill will not occur in the future, the probability of such a spill is low.

E. The Five-Year Leasing Schedule as a Withholding Mechanism

OCS areas omitted from the five-year schedule or appearing late in the schedule may have great significance in the nation's effort to increase the domestic supply of oil and gas. The June 1, 1980, schedule (Table 21) is a case in point. The alternative schedule proposed by DOI in April 1981 (Table 22) advances sales in high-potential basins of Alaska and could result in production increases of several million barrels per day by 1995. Both schedules were prepared from the same data base; thus, such projected production increases are achieved solely by earlier scheduling and more frequent sales, particularly in the high potential basins in the Alaskan OCS.

F. Litigation

The most serious disruptions of scheduled sales have occurred as a result of legal challenges. All recent OCS lease sales, except Sale #43 in the South Atlantic, have been subject to litigation. The consequent postponement of sale dates, followed in many cases by legal considerations of a lessee's right to commence drilling operations, has created an aura of uncertainty regarding all sales, particularly so in frontier areas. NEPA's EIS requirements have been the most frequently used instrument for such court challenges; however, other environmental statutes contain citizen suit provisions on which challenges can be based.

IV. Coastal Zone Management Act

In 1972, Congress passed the CZMA to establish a national policy and develop a national program for the management,

beneficial use, protection, and development of the land and water resources of the nation's coastal zone. The 1972 Act was intended to encourage and assist states to create management programs to "preserve, protect, develop and wherever possible restore the resources of the coastal zone of the United States."[45]

The CZMA recognized the states as the focal point for coastal zone planning and management. The states could delegate some or all of their responsibility to local governments, or to area or interstate agencies. Encouragement for the states to become active in coastal zone management was provided by a series of financial grants to develop and administer CZM programs.

An applicant for a federal permit must certify that his proposed activity in the coastal zone is in compliance with a state's federally approved CZM program. Before a federal permit can be issued, the state must certify that it concurs and that it was given six months to make such a finding. If a state rejects the consistency certification, the permit cannot be issued unless the Secretary of Commerce overrides the state's action on his own initiative or on appeal by the applicant. The grounds on which the Secretary can override a state consistency decision are extremely narrow. Since there is no time limit within which he must act, a final decision can be delayed indefinitely.

By 1976, when the CZMA was first amended, only the state of Washington's CZM program had been approved and the consistency certification issue had not surfaced as a potentially major problem for industry. As a consequence of the 1973-1974 oil embargo the nation recognized the need to accelerate domestic oil and gas exploration, particularly offshore. The thrust of the 1976 amendments was to assist the states to meet the challenges and impacts of accelerated OCS oil and gas activity. Congress perceived that its amendments would encourage new or expanded oil and natural gas production from the nation's OCS in an orderly manner "by providing for financial assistance to meet state and local needs resulting from specified new or expanded energy activity in or affecting the coastal zone."[46]

Two major changes were made in the CZMA to accomplish this goal. First, a Coastal Energy Impact Fund was created to finance public facilities and services. Second, the states' consistency powers were extended to include Exploration and Development and Production Plans submitted by operators on the OCS. Thus, all post-sale offshore oil and gas activity required state consistency certification before it could begin.

Following the passage of the 1976 amendments, the oil and gas industries became aware of the potential for delay and other problems the Act created by the expanded consistency provisions. API challenged the National Oceanic and Atmospheric Administration's (NOAA) approval of California's and Massachusetts' proposed CZM programs, charging that NOAA did not comply with requirements set out in the 1976 amendments as they applied to an energy facility siting procedure in the CZM program, and that NOAA did not adequately consider the national interest. API was not upheld by the courts.

As of September 1981, 20 state and five territory CZM plans were approved by the NOAA. An additional six states' plans were in various stages of completion, and it appeared that Georgia, Virginia, Minnesota, Texas, and Illinois would not participate in the CZM program.

During the 1976-1980 period, considerable controversy developed around the application of Section 307 consistency provisions. Some states (notably California) have asserted that such activities as OCS tract selection, lease stipulations, and lease sales are federal activities "directly affecting" the coastal zone and therefore fall within the coverage of the federal consistency provisions in Section 307 (c) (1). In effect, these coastal states contend that DOI must agree to all OCS tract selection and lease stipulations recommended by them. DOI maintains that pre-lease OCS activities do not directly affect the coastal zone.

A serious consistency controversy surfaced between the State of California and DOI regarding OCS Lease Sale #48, where tracts offshore of southern California were leased. A controversy also existed before Sale #48 between DOI and the Department of Commerce as to whether such pre-lease activities as tract selection or lease stipulations were covered by federal consistency provisions. On December 5, 1978, the California Coastal Commission wrote to the President, requesting that the issue be settled before OCS Lease Sale #48. A Department of Justice legal opinion on the subject was issued April 20, 1979, saying that Section 307 (c) (1) was applicable to DOI's pre-lease sale activities, but only if those activities "directly affected" the coastal zone. In May 1979, DOI notified the State of California that none of its pre-sale activities in regard to Sale #48 had a direct effect on the California coast. California disagreed and requested mediation of the dispute by the Secretary of Commerce as provided for by Section 307 (h) of the CZMA. A public mediation hearing was held in Long Beach, California, on September 7, 1979, followed by a private conference on October 19, 1979. The mediation process was unsuccessful, but the sale was eventually held.[47]

As a result of the controversy in lease sale No. 48 concerning state consistency review, API and Western Oil and Gas Association proposed amendments to the Congress in 1978-1980. The proposal requested that Section 307 (c) (3) of the CZMA be amended to apply only to activities conducted in the coastal zone. But Congress felt it had addressed the consistency issue in its 1976 amendments to the CZMA and that industry was unable to prove that consistency certifications had delayed or disrupted OCS activities.

Congress passed the Coastal Zone Management Improvement Act of 1980 after a series of oversight hearings. Consistency provisions were not changed. The new act merely clarified and expanded the policy section of the statute (Section 303); provided for additional grants to states for resource management, and for urban waterfront and port improvement (Section 306 A); encouraged the states to inventory and designate "coastal resources of national significance"; and authorized appropriations through September 30, 1988, for most grants.

On May 28, 1981, DOI held a lease sale of 81 tracts off central California. A lawsuit to block the sale was filed by the state of California and a number of local governments and environmental groups. The state challenged the DOI proposal under the consistency provisions of the CZMA, NEPA, OCSLA, Endangered Species Act, and Marine Mammal Protection Act. The U.S. District Court for the Central District of California granted summary judgment to California on its claim that the lease sale would directly affect the state's coastal zone, and that therefore under the CZMA there would have to be a determination that the federal proposal be consistent with the state's CZM program. The Court ruled against California on its claim that the sale violated NEPA, OCSLA, the Endangered Species Act, and the Marine Mammal Protection Act. Both the state and DOI have appealed the decision. Pending the outcome of these appeals, DOI has decided to delay its decision to hold a lease sale in four northern California areas until at least 1983.

In summary, the CZMA has the effect of providing coastal states with virtual veto power over federally licensed or permitted activities on the OCS. The veto applies if, in the opinion of the coastal state, federally approved activities will not be carried out in a manner consistent with the federally approved CZM program in that state. The CZMA and its regulations enable coastal states with approved CZM plans to delay and, in some instances, to prohibit the issuance of federal permits, including those needed under OCS oil exploration and production plans. This process has resulted in some lengthy delays in offshore development, and recently resulted in the stoppage of OCS Sale No. 53, offshore central California.

The federal consistency provisions of CZMA seem to be unnecessary. Adequate procedures for considering state comments and recommendations already exist. The OCSLA, as amended, requires the Secretary of the Interior to accept a state's recommendations as to the size, timing, and location of lease sales, and as to development and production plans, if the Secretary determines that they provide for a reasonable balance between the national interest and the well-being of citizens of the affected states.

V. Marine Sanctuaries Program

The Marine Sanctuaries Program was established by Title III of the Marine Protection, Research and Sanctuaries Act of 1972. Although only four pages in length, the potential impact of this program has stirred considerable controversy over the past several years. The legislative history indicates that the intent was to provide a scheme for multiple uses of marine resources while providing protection for specific marine environments. The Act authorizes the Secretary of Commerce (with Presidential and Congressional approval) to designate areas of the ocean and certain other waters as marine sanctuaries for the purpose of "preserving or restoring such areas for their conservation, recreational, ecological, or esthetic values." They may be designated outward to the edge of the OCS and also in the Great Lakes and their associated waters. The Secretary of Commerce is empowered to issue

"necessary and reasonable regulations" to control activities within the sanctuary through the guidance of NOAA.

NOAA published draft site-selection criteria and as a result over 170 nominations were received by February 1978. These were reduced to approximately 100 for further consideration.

Revised regulations for clarification of the policies and objectives of the program were issued in July of 1979. These regulations included the criteria and procedures for nominating, evaluating, and designating areas as sanctuaries.

If the listed areas meet one or more of the following key criteria, further consideration is given.

- The area contains important habitats on which rare, endangered, threatened, or valuable species depend.
- The area contains a marine ecosystem of exceptional productivity.
- The area provides exceptional recreational opportunity and values.
- The area contains historic or cultural artifacts of widespread public interest.
- The area contains distinctive or fragile ecological or geologic features of exceptional scientific research or educational value.

The next step is to select "active candidates" from this list for further evaluation. The criteria for selecting active candidates are more definitive.

- The severity and imminence of existing or potential threats to the resources, including the cumulative effect of various human activities that individually may be insignificant
- The ability of existing regulatory mechanisms to protect the values of the area's resources and the likelihood that sufficient effort will be devoted to accomplishing those objectives without creating a sanctuary
- The esthetic qualities of the area
- The type and estimated economic value of the natural resources and human uses in the area that may be foregone if a sanctuary were established
- The economic benefits to be derived from protecting or enhancing the resources within the proposed sanctuary area.

Six marine sanctuaries have already been designated:

- The Monitor National Marine Sanctuary was designated to protect the Civil War ironclad, the U.S.S. Monitor. The sanctuary is one mile in diameter and is located southeast of Cape Hatteras, N.C. It was established in January 1975.

- The Key Largo Coral Reef National Marine Sanctuary was established in December 1975 to provide management and enforcement for the protection of a 100-square-mile coral reef area south of Miami.

- Channel Islands National Marine Sanctuary, off the coast of California and adjacent to the northern Channel Islands and Santa Barbara Island, consists of 1,252 square miles and was designated in September 1980. Its purpose is to protect valuable habitats for marine mammals and sea birds.

- Looe Key National Marine Sanctuary, designated in January 1981, consists of five square miles of a submerged reef southwest of Big Pine Key, Florida.

- Gray's Reef National Marine Sanctuary is a 17-square-mile live bottom area east of Sapelo Island, Georgia. This is considered to be a very productive and unusual habitat. It was designated in January 1981.

- The Point Reyes-Farallon Islands National Marine Sanctuary, also designated in January 1981, is 948 square miles offshore of San Francisco, California. It contains a diverse array of marine mammals and birds.

There are seven other candidates in various stages of evaluation for possible marine sanctuary designation:

- Flower Garden Banks in the Gulf of Mexico
- Monterey Bay, offshore California
- Waters southwest of St. Thomas, Virgin Islands
- Waters around Mona and Monita Islands, Puerto Rico
- Waters around Culebra and Culebrito Islands, Puerto Rico
- Nantucket Sound, offshore Massachusetts
- Waters off Maui, Hawaii.

When an active candidate has been selected, an issue paper is developed that analyzes the area's unique features and possible boundary and regulatory alternatives. Public workshops are held to discuss the information reviewed in the issue paper and to solicit public opinions on the establishment of the sanctuary. If review warrants proceeding, a DEIS is prepared that analyzes all facets of

the environment being considered and regulatory options that are available. Public hearings are held to comment on the DEIS.

When a marine sanctuary is recommended for approval, the FEIS, with input from other federal agencies, is transmitted to the President. The sanctuary designation becomes effective after Presidential approval. Two actions can block this approval:

- If a sanctuary includes state waters and is deemed unacceptable by the Governor, the Governor may nullify the designation of all or part of the state waters or certain terms or regulations affecting the state waters.

- Both Houses of Congress may adopt a concurrent resolution that disapproves the designation or any of its terms. This two-house Congressional veto provision was added as an amendment to Title III when the program was reauthorized for fiscal year 1981.

The original thrust of the program was to establish small, discrete areas. However, emphasis was later placed on the prohibition or severe restriction of petroleum activity in large areas. The proposed Georges Bank Marine Sanctuary encompasses approximately 20,000 square miles; the Santa Barbara Channel Islands Marine Sanctuary, 1,252 square miles; and the proposed Flower Gardens Marine Sanctuary, approximately 276 square miles (to protect 14 square miles of coral reef in the Gulf of Mexico).

Two areas, one proposed and one already designated as a sanctuary, have high energy potential: the proposed Flower Gardens Banks and the designated Santa Barbara Channel Islands. Regulations associated with a designation would prohibit all future oil and gas operations on unsold lease tracts in that area. In the Santa Barbara Channel Islands case, however, NOAA has responded to sharp criticism and has suspended the oil and gas prohibition until a regulatory analysis can be prepared. Other areas with potentially large amounts of oil and gas, especially vast areas of offshore Alaska (200,000 square miles), have been or will be proposed as sanctuaries.

In most cases, NOAA has not justified its categorical exclusions of energy development in vast ocean areas. Indeed, given the environmentally safe manner in which oil and gas activities are conducted under programs administered by other agencies of the federal government, actions excluding energy development in such areas seem unjustified.

Through 1980, more than 25,000 wells had been drilled in U.S. waters,[48] yet there has been only one offshore platform accident that resulted in significant quantities of oil reaching nearby shores -- the accident in the Santa Barbara Channel in 1969. Both government and private scientific investigators report that there is no evidence that permanent damage resulted from that oil spill and that the area has recovered from any temporary damage (see Chapter Six).

In the northern Gulf of Mexico, the most explored offshore geologic province in the world, no significant adverse environmental effects have been reported. In fact, although large-scale drilling and production operations in the area began some 30 years ago, the fish catch in the Gulf has tripled. The National Marine Fisheries Service reported that in 1950 the commercial fish catch in the Gulf of Mexico amounted to some 571 million pounds and was valued at $50.4 million. In 1980, the nearly 2-billion-pound commercial fish catch in the Gulf of Mexico was valued at $482 million.[49]

The increase in the catch is not, of course, attributable exclusively to petroleum operations. Rather, new fishing technology, an improved fishing fleet, and the taking of large quantities of menhaden (a fish formerly considered noncommercial) account for the marked rise in tonnage However, the increase does show that petroleum operations are compatible with commercial and recreational fishing. In fact, the more than 3,000 platforms in the Gulf of Mexico have provided foundations for the growth of sea plants and invertebrates, contributing to the first step in the marine food chain. About a dozen or more species of fish (virtually unknown in the area before drilling operations began there) can now be found near the platforms.

AIR

I. Overview of Exploration and Production Requirements Under The Clean Air Act

The general provisions of the Clean Air Act are discussed in detail in Chapter One of this report. The specific procedures for pre-construction review of major oil and gas facilities are dependent upon the attainment status of the National Ambient Air Quality Standards (NAAQS) for each pollutant to be emitted in significant quantity by the facility. Recent studies have indicated that the pre-construction review process could be simplified, thereby allowing significant cost and time savings and improving the efficiency and certainty of industrial planning and development.[50] In the case of the oil and gas industries, the problems of delay and uncertainty (and in some cases, project abandonment or project redesign) that have been encountered by individual companies seeking to expand or construct new facilities since passage of the 1977 Clean Air Act Amendments are expected to escalate as efforts to develop and produce domestic energy resources intensify in the decade of the 1980's.

A. Effects of Prevention of Significant Deterioration and Nonattainment Requirements on Oil and Gas Exploration and Development

New and modified facilities involved in every phase of the oil and gas industries, from exploration to final use, are subject to the complex set of Prevention of Significant Deterioration (PSD) and/or nonattainment regulations, depending upon their geographic

location. Such review is applicable to each pollutant emitted by a new source (in most cases, several pollutants are involved).[51]

Cases of production losses attributable to PSD and nonattainment have been documented. At the West Hastings field in Texas, production of 4 thousand barrels per day (MB/D) of oil has been delayed by Texas Air Control Board and EPA restrictions on the use of gas-lift compressors. In North Dakota, restrictions on gas flaring have halted production of 1.4 MB/D at Killdeer Field. At USA#1-a, in Perry County, Mississippi, a five-month delay was imposed by state agency requirements that a new permit be obtained for a new oil well only 50 feet from another well that was abandoned due to control problems Limits on H_2S emissions at the Ute Dome natural gas field in New Mexico have curtailed production of 39 million cubic feet of gas per day.[52] In the case of Exxon's Santa Ynez (a floating offshore storage and treating facility with tanker loadings off the California coast), initial EIS findings showed there would be no significant air quality impacts. EPA later notified Exxon that an air quality permit would be required (the first time EPA extended jurisdiction over OCS air emissions) and after extensive litigation and the application of additional emission controls, Exxon was permitted to proceed with development of this $380 million facility. Oil production of up to 40 MB/D was finally initiated in April 1981 after a seven year delay. This case is discussed in more detail in Chapter Seven.

Shell Oil Company's $400 million BETA Project located nine miles offshore southern California encountered similar air permitting related delays. An air permit was issued by the South Coast Air Quality Management District authorizing construction of the necessary onshore facilities. Since this permit was issued prior to the OCSLA air regulations, described below, a controversy arose over the offshore project's impact on onshore air quality. Rather than prolong debate on the issue, Shell volunteered to undertake further emission reductions and offsets, even though studies demonstrated emissions from the offshore project did not significantly impact onshore air quality. The offsets had to be obtained from as far away as Ventura County, approximately 88 miles from the BETA Project.

The 1978 OCSLA Amendments give DOI responsibility for regulation of OCS air emissions. On May 10, 1979, DOI's USGS proposed air emission regulations These proposed rules were the subject of considerable controversy and resulted in comments from state and local governments, oil producers, and other interested parties. After reviewing the comments, USGS published final regulations on March 7, 1980. On the same date, USGS published draft air quality regulations applicable only to OCS activities offshore California.

The regulations require that each proposed OCS facility be reviewed on an individual basis to determine its individual onshore air quality impacts, and reviewed in conjunction with other nearby OCS facilities to predict cumulative onshore impacts. A new, modified, or revised exploration plan or development and production plan may be exempt from further air quality review if projected

emissions are determined to be less than or equal to emission exemption amounts calculated for the facility.

For a facility that is determined not to be exempt, the lessee is required to use an approved air quality model to determine whether the projected emissions of those air pollutants from the facility result in an onshore ambient air concentration above the significance levels as defined by USGS. Projected emissions of volatile organic compounds (VOC) (that are not exempt) and projected emissions of any air pollutant, which will result in an onshore ambient air concentration above the significance level, are deemed to significantly affect the air quality of the onshore area for that pollutant.

Projected emissions of any pollutant, other than VOC, that will significantly affect a nonattainment area must be fully reduced through the application of Best Available Control Technology (BACT) (under OCS regulations) and, if necessary, through the application of additional emission controls or acquisition of offshore or onshore offsets. Only BACT needs to be applied if the area to be significantly affected is an attainment or unclassifiable area. However, the lessee must use an approved model to determine whether the emissions of total suspended particulates (TSP) or SO_2 that remain after the application of BACT cause the maximum allowable increases over the baseline concentrations to be exceeded. If the maximum allowable increases are exceeded, additional emission controls must be applied.

Thus, the OCS rules impose much stricter requirements than stated in the OCSLA Amendments, which require "...compliance with the national ambient air quality standards pursuant to the Clean Air Act...to the extent that activities authorized under the OCSLA significantly affect the air quality of any State."[53] In essence, the USGS permissible limits of acceptable air quality impact correspond to the PSD Class I increment levels rather than the NAAQS. The proposed significance levels for California are even stricter than the PSD Class I increments. In essence, the entire U.S. coastline is treated as a PSD Class I area with regard to OCS operations.

Excerpts from recent DOI DEISs on OCS Sale No. 68 (Southern California) and OCS Sale No. 53 (Central and Northern California) indicate that the air quality impacts predicted from OCS operations are minor.

- <u>OCS Sale No. 68 predicted impacts</u>:
  - The predicted maximum annual average onshore concentrations for nitrogen dioxide (NO_2), SO_2, and TSP resulting from offshore operations will be <u>well below</u> the 1 microgram per cubic meter level considered significant by DOI.
  - The predicted short-term averages are within DOI's allowable increments.

- Ozone precursors will not be emitted in a proportion favorable for formation of photochemical oxidants.

- OCS Sale No. 68 is not expected to cause any air quality violations nor deteriorate air quality to a degree considered significant, nor to significantly affect onshore visibility or odor levels.

● <u>OCS Sale No. 53 predicted impacts</u>:

- In general, development will not significantly degrade onshore air quality. The DOI increment of air quality deterioration considered significant could be marginally exceeded in several areas. But this could be further mitigated if necessary. (It should be stated that the DEIS analysis assumes worst case conditions, i.e., maximum emission rates by assuming simultaneous operation with the lowest degree of emission controls, and all OCS operations located at the 3 mile limit.)

- OCS Sale No. 53 activities will probably not cause violations of state or federal air quality standards.

- A small degree of additional emission control for NO_2 and TSP would prevent any possible violations of standards and would reduce pollutants below levels considered significant by DOI.

- Based upon worst case assumptions, more stringent controls of reactive hydrocarbon emissions would be required to prevent further oxidant standard violations.

- OCS Sale No. 53 activities are not expected to affect onshore visibility or odor levels.

II. Exploration Operations

The potential for air pollution caused by the exploration for oil and gas is quite small, primarily because of the small number of rigs that usually operate in any given area at one time and because modern drilling operations do not contribute significantly to air pollution.

Geophysical surveys for oil and gas also do not contribute significantly to the air pollution problem, because seismic operations require a minor amount of induced energy and explosives. Exploratory core-drilling operations may emit small quantities of contaminants intermittently into the atmosphere.

III. Drilling Operations

A. General

Air emissions during drilling operations occur principally from engines. Approximately 90 percent of all drilling rigs and support equipment are powered by diesel engines, about 9 percent are powered by natural gas- or LPG-fueled engines, and the remaining are totally powered by electricity, normally with an internal combustion engine used as a standby. The pollutant of greatest magnitude and concern is nitrogen oxide (NO_x), which in many instances exceeds the 100 ton per year EPA definition of a major pollutant source. SO_2 will be emitted if the engine fuel contains sulfur, but is usually of minor significance. The major source of VOC emissions is exhaust emissions from engines.

B. Onshore Drilling

Drilling rigs are used on land for either exploration drilling or development drilling. The total NO_x emissions for the onshore drilling industry has been estimated as 153 tons per day, with 118 tons per day attributed to diesel engines and 35 tons per day to gas-fueled engines. A survey of 24 land drilled wells, with an average well depth of 5,840 feet and an average requirement of 494 horsepower (hp), indicated an average NO_x emission rate of 0.11 tons per day, or 0.007 tons per well.

C. Offshore Drilling

A large self-propelled semisubmersible drilling vessel drilling a typical well of 14,000 feet over a period of 165 days would emit approximately 1.2 tons per day NO_x; 0.26 tons per day carbon monoxide (CO); 0.09 tons per day hydrocarbons; 0.1 tons per day of particulates; and SO_2 emissions would be about 0.16 tons per day

A very large self-propelled drillship uses dynamic positioning instead of fixed anchors for deepwater drilling anywhere in the world. It utilizes 16,000 hp for propulsion when under way in the open seas. Calculated average emissions for the drillship when drilling are 2.1 tons per day NO_x, 0.46 tons per day CO, 0.17 tons per day hydrocarbons, 0.15 tons per day particulates, and 0.19 tons per day SO_2.

A survey of eight typical offshore drilling wells in the Gulf of Mexico indicates an average requirement of 1,023 calculated hp for drilling a 10,500-foot well. The average power consumption was 455 hp, and the average drilling time was 52 days. The average NO_x emission rate was 0.17 tons per day or 0.026 tons NO_x per well.

D. Controls

1. Power Generation

NO_x control of internal combustion engines is accomplished by changing certain engine operating conditions and thereby modifying

the basic combustion process. Adjusting the fuel/air ratio on gas-fueled engines is a relatively simple control to reduce NO_x. However, a fuel penalty occurs and the level of CO is increased. The setting of the fuel/air ratio so that the NO_x and CO emissions are equal is currently specified by some regulatory agencies to be the best NO_x control. Combustion chamber modifications and catalytic reduction are potential controls for the future.

Catalytic converters on some diesel engines are being used to control NO_x emissions; however, the use of catalytic converters is not yet a well accepted practice in drilling or production. Retarding the fuel injection or injecting water into diesel engines are two means of lowering the combustion temperatures for diesel engines that may develop into acceptable NO_x control methods in the future.

2. Fuel System

VOC emissions from the engine fuel systems are best controlled by good maintenance to prevent leaks. Because of the use of the drilling equipment, the valves and connections are portable and particularly susceptible to leaks. However, the fuels in use do not normally emit a significant amount of reactive hydrocarbons, and maintenance procedures are followed to minimize fuel costs.

3. Mud System

VOC and occasionally H_2S enter the well bore while drilling and become entrained in the drilling fluid. These entrained gases are normally removed in the mud maintenance system at the shale shaker, degasser, and mud pits. They occur sporadically and are negligible except during uncommon "well kicks" or uncontrolled flow resulting from too little mud weight. When these emissions are sufficient to support combustion they are oxidized in a flare.

Intrusion of H_2S gas into the mud may occur in some geographic areas. This is usually controlled by chemical means. Iron sponge is commonly added to the mud system to react with the H_2S to form iron sulfide. Zinc carbonate and copper carbonate have been similarly used

IV. Production Operations

A. Onshore Production

Oil and gas production is transferred from the well by pipeline to a separation and treatment facility where the oil and gas are separated for sale, and water is removed for disposal. Depending upon the separation, treatment, and sales methods required, free water knockouts, liquid/gas separators, heaters, settling tanks, storage tanks, pumps, compressors, power generation equipment, gas scrubbers, and drip pots may be required.

Emission sources such as pumps and compressors are powered by either gas engines, gas turbines, or electric motors; and heaters

are equipped with gas-fired burners. Diesel engines are less commonly used for onshore power generation, as either electric power or adequate fuel gas is usually available and can be safely used. NO_x in exhaust gases from these combustion devices is the primary source of pollutants. Other accessory equipment, including valves, fittings, connections, tanks, and pits, are sources of hydrocarbon emissions.

Perhaps the production area that has been impacted most by the Clean Air Act is the heavy oil production area located in Kern County, California. The following constraints imposed by the Clean Air Act and its attendant regulations impede an increase in heavy oil production in that area:

- The construction ban
- Cumbersome permitting procedures for new facilities
- Time-consuming permitting procedures
- NAAQS that may go beyond health requirements (for example, in California)
- Inflexible definitions of attainment and nonattainment areas
- Fixed attainment deadlines
- Rigid offset requirements
- PSD increments.

If the Clean Air Act is strictly interpreted, with all of these constraints in effect, heavy oil production in Kern County would be limited to a range somewhere between the current level of about 400 MB/D and a higher level of about 600 MB/D. This higher level could be approached if all currently permitted steam generators are put into production. However, with the elimination of the construction ban, improved permitting, and relaxation of other constraints, production of heavy oil in Kern County could increase to a level of about 940 MB/D by 1990.[54] Kern County heavy oil fields now contain about 20 billion barrels of oil in place, most of which cannot be produced using conventional methods. The potential production is thus large, and could be an important factor in U.S. energy production.

Although methods other than steam injection are being tested, the bulk of heavy oil recovery is attained using steam injection methods. In Kern County, steam for injection is generated using an oil field steam generator, which is located close to the injection wells. Nearly all generators use crude oil from producing leases as fuel. The burning of this crude oil for steam generation produces a number of emissions, including primarily NO_x, sulfur oxides (SO_x), and particulates. Hydrocarbons may also be emitted from producing wells.

Further expansion of heavy oil production in Kern County depends upon the installation of additional steam generation capacity. However, because steam generators produce emissions, offsets are required. Improved pollution control technology can increase the very limited supply of offsets and thus allow for more or expanded steam generators. The industry is relying on new control technology to increase the availability of offsets and provide for growth in the steam generator population without degrading air quality.

Technology currently exists for controlling SO_x emissions on the steam generators, and NO_x control technology is developing. Most hydrocarbon emissions can be controlled with existing technology. However, no proven high efficiency technology currently exists for controlling particulate emissions from steam generators.

Control of sulfur compounds is achieved through the use of Claus sulfur recovery plants, which produce elemental sulfur. This results in a sulfur recovery efficiency of approximately 96 percent. High CO_2/H_2S ratios adversely affect recovery efficiencies. Higher recoveries are achieved through the addition of a tail gas unit to process the gas emitted from the Claus sulfur plant. In cases where small quantities of H_2S have to be removed, techniques such as iron sponge and molecular sieves are utilized.

Three different control technologies have been approved as BACT and are currently permitted for use on large sour gas plants in the Overthrust Belt in southwest Wyoming and northeast Utah. They are Cold Bed Absorption (CBA), Shell Claus Off-Gas Treating (SCOT), and the Beavon-Stretford process. The typical sulfur recovery efficiencies for these technologies are shown in Table 23. A Claus sulfur recovery process is an integral part of each of the three tail gas units specified in this table.

The CBA process involves treatment of the tail gas from the Claus process to convert additional H_2S and SO_2 to sulfur. The CBA process provides a final catalytic converter at low temperature to shift reaction equilibrium to increase conversion by the Claus reaction. This is an oxidation process that produces elemental sulfur. The tail gas is incinerated and SO_2 is emitted.

The SCOT process reduces the Claus tail gas to H_2S over a catalyst. Then the H_2S stream containing 40 percent CO_2 is absorbed in an alkanol-amine section. H_2S is stripped from the amine and recycled to the Claus unit. H_2S not absorbed is burned to SO_2 and discharged.

The final process cited is the Beavon-Stretford process, which first reduces all sulfur compounds in the Claus tail gas to H_2S by hydrogenation and hydrolysis. The Beavon-Stretford process is then used to absorb the H_2S in an oxidizing alkaline solution, which converts the H_2S to elemental sulfur. The tail gas from this process contains carbonyl sulfide (COS) and small amounts of H_2S and carbon disulfide (CS_2). It does not require incineration prior to being emitted to the atmosphere.

TABLE 23

Current Control Technologies Permitted for Large Natural Gas Processing Plants (Sour Gas Plants) Located in the Wyoming/Utah Overthrust Belt

	Recovery Process			
	Claus plus CBA*	Claus plus SCOT†	Claus plus Beavon-Stretford	Comment
Total sulfur recovery efficiency§	98.6%	99.7%	99.7%	Assumes sulfur-free fuel gas used in burners
Pollutants emitted after control is applied	SO_2	SO_2	COS & H_2S	Small amounts of CO may also be emitted
Pollutant emission rate assuming a 250 MMSCF/D¶ inlet stream @ 15% H_2S	3,694 lb/hr SO_2	793 lb/hr SO_2	720 lb/hr COS 13.5 lb/hr H_2S	
Total sulfur recovery (short tons per day)	1,562	1,579	1,579	

*Cold Bed Adsorption Process.

†Shell Claus Off-Gas Treating Process.

§Higher sulfur recovery efficiencies are possible with additional operating and capital expenditures (New Source Performance Standards for refinery sulfur recovery processes require 99.9 percent control efficiencies).

¶Million standard cubic feet per day.

SOURCE: American Petroleum Institute testimony before the U.S. Senate Environment and Public Works Committee, July 8, 1981.

B. Offshore Production

Support facilities used while drilling are often required for production. These include diesel-powered electric generators for providing electricity to the quarters, galley, recreation room, equipment controls, sanitation, and navigational aids. These electrical loads are nominal. Cranes, heating systems, firewater systems, and desalination units are also fueled by diesel.

There are additional requirements for diesel power for production, including gas compressors, pumps, heaters, and gas dryer regenerators. Gas engines are also used offshore when fuel gas is available. Platforms with large power requirements may use gas turbines as the prime mover when adequate gas supplies are available.

Water injection has been considered by regulatory agencies for NO_x control with gas turbines in the future. However, an offshore source of pure water to prevent scale formation is hard to find.

Fugitive VOC emissions from leaks may occur from various equipment containing a VOC source. They are usually small and are best controlled by a good program of detection and repair. An API study found over 173,000 equipment components in production operations. Less than 5 percent of the components leaked, indicating that fugitive VOC emissions usually occur from only a small fraction of the potential emission sources.

WATER

I. Onshore Exploration and Development Drilling and Production Operations

This section discusses the effect of pre-drilling, exploratory drilling, and production activities on water quality Since the first commercial oil well in the United States was drilled in 1859, about 2.5 million onshore wells have been drilled. Onshore drilling presently continues at an annual rate of about 50,000 wells, with total depths ranging from hundreds of feet to greater than 20,000 feet. In 1978 the average depth of wells drilled onshore was 4,814 feet.

A. Onshore Drilling Operations

Onshore drilling operations have short-lived environmental impacts. Drilling wastes consist mainly of used drilling fluid (mud) and formation solids (cuttings).

1. Drilling Fluids

In order to discuss the environmental impacts of drilling fluids, or "muds," it is first necessary to understand their

composition and use. For a discussion of this subject see the Industry Operations section of this chapter.

a. Reserve Pits[55]

When drilling onshore wells, a reserve pit, or sump, is used to store the drilling mud and cuttings and for final disposal. (In urban areas, a tank rather than a sump is used.) Prior to arrival of the rig, a reserve pit is excavated adjacent to where the rig and associated mud equipment will be sited. The pit is deeper near the mud-processing equipment to allow the heavy solids to settle out. It is sized according to the well depth planned. When drilling a shallow well, the total volume of mud and cuttings may only be 2,000 barrels. However, deep wells may have volumes as high as 100,000 barrels. In addition, allowance is made for rainfall. It is important that the walls of the reserve pit be high enough to provide 3 to 5 feet of topsoils on top of the drilling mud and cuttings after backfilling. A larger, shallower reserve pit is preferable, because the final disposal will be achieved more quickly and efficiently. Sometimes regulations, unique geography, and environmental considerations require an impervious liner in the reserve pit.

b. Disposal Methods

Three methods of disposing of drilling fluid are used.

Backfilling a Reserve Pit. This method is by far the most common disposal method. It results in a consolidated mud lens 3 to 5 feet below the surface. Before backfilling can begin, the top aqueous layer must be removed and any excessive free oil must be skimmed. After the oil is skimmed, the aqueous layer is clarified by mixing or broadcasting the pit area with flocculants such as polyacrylamide or gypsum. Flocculation produces a denser colloidal slurry, decreasing the volume of waste and increasing the efficiency of the dewatering process.

After clarification, the aqueous layer is allowed to evaporate or the pit dike is cut and the fluid drained. Before draining, certain chemical and/or biological tests are conducted to ensure that the released fluid meets regulation guidelines. The aqueous layer can also be removed by vacuum truck and injected into the well that was drilled (if it is to be plugged and abandoned) or transported to a nearby injection well and disposed of.

Once the aqueous layer has been removed, backfilling the reserve pit takes place. Care is taken to return the area to original contours and to replace the topsoils evenly. This method allows ample time for the remaining drilling solids to undergo further dewatering. The dry topsoils of the reserve pit walls also aid in the final dewatering as they are slowly moved over and mixed with the waste muds and cuttings. When the closure process is complete, the area is ready for return to its original use.

Vacuum Truck Removal to a State-Approved Disposal Site. This method is only used in environmentally sensitive or urban areas, where there is some concern that surface water, groundwater, and soil may be contaminated by the leaching of trace amounts of metals from buried reserve pits. The characteristics of drilling mud greatly retard leaching from the reserve pit, especially after disposal, which helps minimize such problems.

Soil Biodegradation. This method consists of spreading the contents of the reserve pit evenly over the drilling location and mixing them into the soil using soil-tilling equipment. Sometimes the pit is first dewatered. In most states this is the preferred method. Studies at Utah State University concluded that land-farming was workable provided adequate site selection and waste treatment techniques were employed.[56] However, one state (Oklahoma) has passed a regulation prohibiting the use of soil biodegradation on agricultural lands.[57]

2. Associated Fluid Wastes

Associated fluid wastes are rainwater, drilling rig washdown water, drill-cuttings wash water, sanitary wastes, and small amounts of miscellaneous chemicals such as drill pipe thread dope and drilling fluid additives. Uncontaminated rainwater (i.e., water that falls outside the drilling rig area) can be channeled away from the activity area and allowed to flow its natural course.

Contaminated rainwater, drilling-rig and drill-cuttings wash water, and the miscellaneous chemicals are contained within the drilling rig area with earthen berms, and the fluid is channeled into the reserve pit or another pit. The collected fluids are disposed of with the fluid portion of the drilling wastes.

3. Pollution Prevention

Pollution prevention is an integral part of the overall drilling process. The environment is protected by drilling system control, surface containment, and discharge limitations for used drilling fluids and associated wastes. In addition, each drilling operation is covered under a Spill Prevention, Control and Countermeasure (SPCC) Plan, as required by the Clean Water Act of 1972. SPCC plans and their requirements are discussed in Chapter Six.

a. Drilling System Control

Drilling system control is maintained by using the proper drilling fluids, the correct casing program, and the proper blowout prevention system. All three of these must be approved and inspected by a designated federal or state agency.

The drilling fluid system prevents pollution by maintaining the correct subsurface hydrostatic pressure in the well bore and is monitored by frequent fluid weight checks. The use of pit-level mud-pump-suction alarms to detect a loss or gain in drilling fluid, the use of gas-detection alarms near the mud flow ditch and shakers

to detect an abnormal amount of hydrocarbon gas, and the use of other drilling fluid system checks/alarms (i.e., chloride content), which provides an early warning of potential problems arising from unknown conditions.

Casing programs are designed and engineered to maintain cased-hole and bore-hole integrity and thus prevent pollution of the surrounding environment. The casing program variables are size (diameter), weight (wall thickness), grade (steel additives content and heat treating), and depth. These variables are optimized by using engineering tables or computer programs to select the proper casing program for depth and amount of subsurface pressures anticipated, drilling fluid weights to control pressures, and strengths and lengths of various casing strings for the anticipated well.

BOPs are hydraulically operated and controlled equipment bolted to the casing at the surface that, when activated, close off the annular space between the casing and the drill string. This prevents the uncontrolled release of drilling fluids, oil, water, or gas if an imbalance in bottom-hole pressure occurs, which could result in a blowout. They are further described in the Industry Operations section of this chapter. BOPs are normally inspected and/or approved by a designated federal or state agency.

b. Containment

Surface containment systems usually include a reserve pit, drilling rig site drainage control, and drip pans beneath rig engines and equipment.

The reserve pit is the central collection site for most waste liquids from drilling operations. Each drill site is laid out, graded, and bermed, to divert rainwater away from the drill site, and allows it to follow its natural runoff course. Rainwater, washdown waters, and other liquids that fall within the bermed area are usually channeled to the reserve pit for collection and storage.

The drip pans are used primarily for the collection of lube oil leaks. These collections are either recycled back through the lube oil system or are transferred to the reserve pit for future disposal.

The liquids in the reserve pits that are collected from all sources around the drilling rig are usually contaminated. After a well has been drilled, the reserve pit is dried and then closed, as previously discussed. In arid parts of the country, the liquids in the pit will rapidly evaporate. In some high rainfall areas, however, the liquids are either hauled to disposal or discharged if uncontaminated. Some states allow intermittent discharge of liquid wastes from drilling reserve pits into surface waters, if the discharge meets state limitations. The waste components for which limitations are normally controlled are oil and grease (O&G), chlorides, and total suspended solids. These limitations are usually expressed as milligrams per liter (mg/l). The discharge

limitations imposed by federal and/or state agencies may vary with the receiving environment. Many states have developed their own specific regulations to protect the environment.

4. Spill Incidents

As shown in Table 24, pollution incidents resulting from exploration and production activities are a small percentage of the total number of incidents reported from the entire oil and gas industry. Spill events occurring during a drilling operation are usually the result of a blowout, a reserve pit failure, or a fuel tank failure. For further discussion, refer to Chapter Six.

B. Onshore Production Operations

1. Disposition of Produced Wastewater

The major waste product of onshore oil and gas production is "produced water," water that exists naturally in an oil and gas formation. It contains oil, salts, trace heavy metals, solids, and organic chemicals.[58] Tables 25 and 26 show the chemical compositions of produced water from two oil-producing areas of the United States. Produced water is typically removed by gravity separation and is disposed of by utilizing one of the following methods:

- Underground injection control (UIC)
- Enhanced oil recovery
- Discharge to surface water (NPDES)
- Evaporation.

Produced water is primarily disposed of by the first two methods.

a. Underground Injection Control

The use of UIC for disposal depends on the availability of formations that have sufficient porosity, permeability, and areal extent to contain the injected water. They usually contain salt water of no commercial value.[59] State oil and gas regulators require permits before a disposal well can be operated. The major intent of the permit process is to ensure that produced water is confined to the disposal formation and does not contaminate fresh water sources.

b. Enhanced Oil Recovery

In 1976, approximately 19.9 billion barrels of produced water were injected underground, 8.6 billion barrels in disposal wells, and 11.3 billion barrels in enhanced oil recovery injection wells.[60] Enhanced oil recovery reinjection wells are also controlled by state oil and gas regulatory agency permits.

TABLE 24

Reported Incidents of
Exploration and Production Oil Spills -- 1979-1980

Production	1979 Number*	1979 %†	1979 Volume (Gallons)§	1979 %†	1980 Number*	1980 %†	1980 Volume (Gallons)§	1980 %†
Onshore	330	3.0	267,993	2.6	105	1.3	101,024	1.4
Offshore	614	5.6	93,345	0.9	574	7.3	115,248	1.6
Total	944	8.6	361,338	3.5	679	8.6	216,272	3.0

*Number = number of reported incidents.
† % = percentage of total reported (incidents or volume).
§ Volume = reported volume (gallons).

SOURCE: Department of Transportation, U.S. Coast Guard, Polluting Incidents In and Around U.S. Waters, Calendar Years 1979 and 1980.

TABLE 25

Pollutants in Produced Water -- Louisiana Coastal*

Pollutant Parameter	Range (mg/l)	Average (mg/l)
Oil and Grease	7 - 1300	202
Cadmium	<0.005 - 0.675	<0.068
Cyanide	<0.01 - 0.01	<0.01
Mercury		<0.0005
Total Organic Carbon	30 - 1580	413
Total Suspended Solids	22 - 390	73
Total Dissolved Solids	32,000 - 202,000	110,000
Chlorides	10,000 - 115,000	61,000
Flow	250 to 200,000 bbl/day	15,000 bbl/day

*Results of 1974 EPA survey of 25 discharges per well.

SOURCE: Environmental Protection Agency, "Development Document for Interim Final Effluent Limitations Guidelines and Proposed New Source Performance Standards for the Oil & Gas Extraction," September 1976.

TABLE 26

Pollutants in Produced Water -- California Coastal*

Pollutant Parameter	Range (mg/l)
Arsenic	0.001 - 0.08
Cadmium	0.02 - 0.18
Total Chromium	0.02 - 0.04
Copper	0.05 - 0.116
Lead	0.0 - 0.28
Mercury	0.0005 - 0.002
Nickel	0.100 - 0.29
Silver	0.03
Zinc	0.05 - 3.2
Cyanide	0.0 - 0.004
Phenols	0.35 - 2.10
Biochemical Oxygen Demand	370 - 1,920
Chemical Oxygen Demand	400 - 3,000
Chlorides	17,230 - 21,00
Total Dissolved Solids	21,700 - 40,40
Suspended Solids	
Effluent	1 - 60
Influent	30 - 75
Oil and Grease	56 - 359

*Some data reflect treated waters for reinjection.

SOURCE: Environmental Protection Agency, "Development Document for Interim Final Effluent Limitations Guidelines and Proposed New Source Performance Standards for the Oil and Gas Extraction," September 1976.

c. Surface Water Discharges

Surface water discharges are controlled by state and federal NPDES permits. The compatibility of the discharged produced water and the receiving surface water determines whether this type of disposal is environmentally acceptable. Some produced water can be discharged into brackish coastal waters and the alkaline lakes found in the southwestern states. Produced water with very low salt content can be discharged to surface ponds and streams. In either case, state or federal agencies limit the O&G content in the discharged produced water. The federal regulations allow up to 72 mg/l of O&G as a daily maximum; state limitations vary.

2. Pollution Prevention

In most cases, produced water that is reinjected underground is never exposed to the surface environment. It is produced from an oil or gas well, separated from the oil and gas through surface processing equipment, and reinjected underground in a continuous operation.

When produced water is disposed of underground in a salt water disposal system, oil removal is maximized for two reasons: first, the oil is a valuable product and economics force maximum recovery; and second, oil in produced water has a tendency to reduce the porosity of the disposal formation. Once restricted, disposal capacity is expensive to restore.

When wastewater is discharged to surface waters, the primary concern is minimizing the amount of O&G. Since there is ample space compared to offshore production platforms, large tanks or surface impoundments are used to allow the water and oil to separate to environmentally acceptable levels

3. Spill Incidents

Accidental spills of oil and/or produced water are minimized by good operating practices. For example, surface impoundments are used to provide emergency storage for large volumes of produced water. Automatic devices are also used to prevent accidental spills. High-level alarms in tanks alert operators that an oil or produced-water tank will overflow if quick action is not taken. Low-pressure alarms will alert them that there is a leak in an underground injection line. Other systems automatically close a full tank and shift oil or produced water to an empty one. Minor leaks from valves and fittings are easily recognized and repaired before they present a safety or environmental hazard. Blowouts sometimes occur when a well is being worked on to restore or increase production. A description of BOP techniques is contained in the Industry Operations section of this chapter.

C. Natural Gas Processing Plants

1. Types of Discharge

There are five types of liquid wastes that could be discharged from a natural gas plant site. The first of these is process water, which is contained as a vapor in the raw gas and is condensed and separated from the gas during processing This process water usually contains small amounts of O&G and may also contain dissolved H_2S, CO_2, and corrosion inhibitors Separated process water is usually piped to a separation pit, pond, or tank for gravity separation of O&G.

The second type of waste discharge is the liquids periodically drained from boiler bottoms to eliminate dissolved solids and sediments from the steam system. These boiler blowdown fluids have high concentrations of dissolved solids and contain small amounts of corrosion and scale inhibitors, as well as anti-foaming agents. These fluids are generally piped to the separation pit or pond to be disposed of with the process water. Boilers throughout the oil industry are slowly being replaced with more efficient directly fired heaters.

The third type of waste discharge is water from cooling towers. The cooling tower is utilized for many functions including the cooling of the gas stream to initiate the condensation of liquids. The cooling-tower bottoms are periodically bled off to remove accumulated dissolved solids and sediments. These water bleeds are generally high in dissolved solids, are alkaline, contain varying amounts of corrosion and scale inhibitors, and may contain traces of oil from leaky exchangers. There is a large amount of evaporation loss in cooling-tower operation and makeup water must be continually added. Like boilers, cooling towers are slowly being phased out and replaced, where possible, with easier to operate air-cooled exchangers.

The fourth type of waste discharge is jacket water. Jacket water cooling systems are used to cool compressors, pumps, and engines in gas plants. These cooling systems are generally "closed systems" and only discharge when there are small leaks and/or equipment failures. The discharge waters in these systems usually contain small amounts of corrosion and scale inhibitors.

The fifth type of waste discharge is surface runoff from rainfall on the plant site and from liquid leaks within the plant area. Surface runoff usually contains small quantities of O&G and small amounts of sulfur compounds, if the raw field gas is sour and requires H_2S treatment.

2. Pollution Prevention

Impoundment is the primary method of containing discharges from a gas plant site. Impoundment utilizes dikes (berms) around the process area to catch and divert liquids into a catch basin or the separation pit or pond. The separation pond provides temporary

storage for the liquid runoffs and also provides for separation of O&G from the water discharges. Automatic devices monitor pressures and liquid levels within the process equipment and sound an alarm if malfunctions occur. If desired, equipment can be automatically shut down in an emergency.

3. Waste Disposal

Methods of disposal of liquid wastes collected in the separation pit or pond depend upon the amount collected. If only small volumes are collected, the liquids may evaporate or periodically be hauled to a state-approved disposal site by vacuum trucks. Gas plants that collect moderate to large volumes for disposal either discharge into a nearby river or use subsurface injection/disposal. River discharge requires an NPDES permit from a state agency and/or EPA. Subsurface injection may be more feasible if the gas plant is sited in an oil field where disposal wells are available. A waste injection/disposal permit from a state agency is required for this type of disposal.

Discharge limitations are generally expressed as O&G content, pH, biological oxygen demand, chemical oxygen demand, and total suspended solids. These limitations are set by the appropriate state permitting agency and/or EPA.

4. Spill Incidents

In natural gas plants there are generally two types of incidents that could cause pollution of a nearby waterway: equipment failures and/or impoundment overflows. Visual inspection and automatic sensing devices, with alarms, allow operators to quickly react to an equipment failure or an impoundment overflow and shut off the flow and initiate remedial action.

D. Federal and State Regulations

Most oil and gas drilling and production activities are regulated by a myriad of federal and state agencies. On federal lands, agencies such as the BLM, USGS, National Park Service, and the BIA have regulatory responsibility for oil and gas drilling and production activities. In addition, oil-producing states also have regulatory agencies. For example:

- Texas -- Texas Railroad Commission
- Oklahoma -- Oklahoma Corporation Commission
- Louisiana -- Louisiana Department of Natural Resources
- California -- California Department of Conservation, Division of Oil and Gas.

These agencies derive their regulatory powers from the numerous federal and state environmental statutes that have been enacted in the past 20 years. Some states have regulated waste discharges since the 1930's through oil and gas conservation statutes.

1. Regulated Discharges

Discharges of wastes into the marine environment are regulated through the federal Clean Water Act NPDES program and through various state-enacted statutes. Each NPDES permit is approved and granted subject to several operating conditions such as waste volume limitations, individual pollutant limitations, and monitoring and reporting requirements. Violation of any NPDES permit condition subjects the discharger to civil or criminal penalties and possible permit revocation.

2. Dredge and Fill (Section 404) Permits

Section 404 of the Clean Water Act prohibits the discharge of dredge or fill material into navigable waters of the United States without a permit, and sets forth the U.S. Army Corps of Engineers as the permitting agency. Thus, almost any construction activity in a pond, lake, river, wetland, or salt marsh, will require a Section 404 permit. The Corps requires detailed engineering and site plans, and a comprehensive description of the dredge or fill material and its handling. If the proposed activity has a substantial environmental effect, mitigation measures may be required. The Corps notifies other federal, state, and local agencies of all permit applications to solicit their review and comments prior to approval. The implementation of Section 404 of the Clean Water Act by the Corps has resulted in unjustified delays in the drilling of many oil and gas wells.

Acting pursuant to Section 404(q) of the Clean Water Act and the Fish and Wildlife Coordination Act, the Corps has executed MOU with the U.S. Fish and Wildlife Service, the National Marine Fisheries Service, and EPA. These memoranda set out the procedures that each of the agencies are to follow in reviewing environmental considerations of Section 404 permit applications. In spite of the 404(q) goal that permits be issued within 90 days of the public notice on each permit, the MOU provide for as much as 300 working days to resolve interagency conflicts. The result is that, even for projects that have a relatively minor environmental impact, much more than 90 days elapse before a decision is reached on many permits.

These delays cause major problems:

- An operator may be obliged to accept onerous environmental requirements to avoid project delays. Rig schedules and lease obligations sometimes force the operator to do so.

- If the operator chooses to put off the drilling of a well while waiting for a resolution of environmental objections, he faces interrupted rig schedules, delays in drilling priority wells, and deferred or lost production.

An approved permit will contain several specific conditions, such as mitigation measures to be undertaken to protect the environment. Violation of these conditions subjects the permitee to penalties and possible permit revocation.

3. Oil Spill Reporting, Cleanup, and Spill Prevention, Control and Countermeasure Plans

The Clean Water Act Section 311 empowers EPA to develop regulations to protect the environment from discharges of oil. EPA regulations require onshore and offshore drilling and production facilities to report the discharge of oil in such quantities as may be harmful. EPA has defined a reportable quantity as that amount of oil that will cause a sheen.[61] Oil spilled onshore that may reach a navigable water must also be reported, even if the oil enters a dry creek bed and never touches water. Oil spills and SPCC plans are discussed in detail in Chapter Six.

E. Special Environmental Considerations

There are certain geographic areas that require special environmental considerations due to their close proximity to wetlands, lakes, streams, and flood plains.

1. Wetlands and Lakes

Drilling and production activities on or next to wetlands or lakes usually require Section 404 permits in addition to the routine operating permits. Activities in these locales will require precautions to prevent pollution of nearby waters. These activities are usually handled like offshore locations, rather than onshore. Extra provisions for site containment, NPDES permits for discharges, and provisions for offsite disposal of drill cuttings may be required.

2. Streams and Flood Plains

Drilling and production activities near streams and in flood plains require stricter-than-normal provisions for onshore and upland site containment to prevent the release of wastes into the nearby waters. Locations near streams will require NPDES permits for site discharges. Locations in flood plains will require site containment provisions that are sufficient to counter the effects of 25- to 100-year storms, depending on the individual location and state regulations.

II. Offshore Exploration and Development Drilling

A. Types of Discharges

Drilling discharges from wells located in state waters are controlled by the respective state regulatory agencies, such as the Texas Railroad Commission and the Louisiana Department of Natural Resources. Drilling discharges into OCS waters are regulated by three agencies: BLM, USGS, and EPA. BLM exercises its authority through stipulations in OCS lease agreements, USGS utilizes OCS Orders, and EPA uses NPDES permits.

The wastes developed during drilling may be classified as either dischargeable (discharged overboard to the marine environment) or nondischargeable (transported to shore for on-land disposal). The overboard discharges consist of water-base drilling muds and formation cuttings, deck drainage water, cooling water, domestic wastes, and sanitary wastes.

1. Drilling Muds

The types of formations encountered while drilling and their pressures are the major factors that determine the types of muds used. In offshore operations, water base drilling muds are normally used. These low toxicity muds are discharged overboard in accordance with applicable state or federal regulations under the limitations set forth in individual NPDES or state permits. EPA is in the final stages of issuing general NPDES permits for certain non-environmentally sensitive portions of the Gulf of Mexico. These permits provide for overboard discharge of drilling muds and drill cuttings with a limitation of "no free oil" controlling the discharge. Discharges occur daily as the mud system is kept in balance for drilling operations. Bulk mud discharges occur when the mud type must be changed to meet new drilling conditions or when drilling operations are completed. Numerous studies have shown that these discharges have little or no impact on the receiving waters.[62,63,64]

2. Drill Cuttings

During drilling, mud is circulated down the drill string and through the bit, where it picks up the cuttings at the bottom of the hole and carries them back to the surface through the annulus between the drill string and the walls of the borehole or casing. The mud is then passed through solids removal equipment (a system of shale shaker screens and hydrocyclones) to remove the cuttings, after which it is returned to the mud tanks for recirculation. The rate of discharge may range from 0.2 to 2.0 cubic meters per hour (1 to 10 barrels per hour), depending on the drilling rate. The drill cuttings discharged to the marine environment consist of solid particles from the formations penetrated, e.g., clays, shales, sandstone, and limestone Chips of rock containing no free oil are generally discharged overboard in compliance with applicable state or federal regulations and fall to the bottom of the sea within a few meters of the drill site.

3. Drill Cutting Washwater

Prior to discharging the drill cuttings overboard, the cuttings are continually washed with water. This water is then discharged to the sea with the drill cuttings. No free oil is allowed to be discharged with the drill cutting wash water.

4. Deck Drain Water

Rainwater and washdown water are discharged from the decks of the drilling facilities. The washdown water is used to keep working areas clean and safe. Rainwater or washdown water collected

from curbed areas, drip pans, or areas having machinery, which may be contaminated, are directed to a gravity separator, referred to as a sump, and discharged through a skimmer pile. These discharges are permitted providing no free oil is discharged. Rainwater or washdown water falling or used on nonprocess areas, such as pipe racks, helicopter pads, and storage areas, is normally discharged without treatment.

5. Sanitary Waste

Discharges from sanitary waste facilities normally include only human body wastes. If treated in a U.S. Coast Guard approved marine sanitation device, overboard disposal is allowed without further limitations. Other types of sanitation devices are allowed to discharge overboard if an appropriate chlorine residual is maintained as required by the NPDES or state permits.

6. Domestic Waste

Domestic wastes include discharge from sinks, showers, laundries, and galleys. These discharges do not impact the environment and are not restricted.

7. Cooling Waters

Cooling water normally consists of once-through seawater that only contacts the internal surfaces of the equipment to be cooled and thus is discharged directly overboard.

8. Produced Waters

The chemical composition of produced water from offshore wells is shown in Table 27. Produced oil, water, and gas are collected at a central facility (e.g., the production platform) for separation. The oil and gas is shipped to shore and the produced water is normally discharged overboard. Under special conditions, the fluids may be pipelined to shore prior to separation. The produced water is then discharged overboard to coastal waters.

A typical offshore produced-water treating facility consists of gravity separation vessels and a clarifier. The type and size of the treatment facility are controlled by the volume and the ease of treatability of the produced water. This equipment is discussed in the Industry Operations section of this chapter.

The discharges of produced water are controlled by state and/or EPA NPDES permits. The EPA Region VI General Permits for the Gulf of Mexico allowed for overboard discharges with a daily maximum oil content limitation of 72 mg/l.

B. Alternate Disposal Methods

Methods other than overboard discharge have been considered for disposal of drilling mud and cuttings. Transporting these materials to an authorized ocean dump site is one alternative. The

TABLE 27

Pollutants in Produced Water -- Texas Offshore

Pollutant Parameter	Range (mg/l)
Arsenic	<0.01 - <0.02
Cadmium	<0.02 - 0.139
Total Chromium	<0.10 - 0.23
Copper	<0.10 - 0.38
Lead	<0.01 - 0.22
Mercury	0.001 - 0.13
Nickel	<0.10 - 0.44
Silver	<0.01 - 0.10
Zinc	0.10 - 0.27
Phenols	53
Biochemical Oxygen Demand	126 - 342
Chemical Oxygen Demand	182 - 582
Chlorides	2,000 - 62,000
Total Dissolved Solids	806 - 169,00
Suspended Solids	12 - 656

SOURCE: Environmental Protection Agency, "Development Document for Interim Final Effluent Limitations Guidelines and Proposed New Source Performance Standards for the Oil and Gas Extraction," September 1976.

additional hazards of standby storage vessels at the drill site, the risk of collisions, the loss due to heavy seas, and the air pollution caused by the transport vessels override the advantages of transporting from one site to another for disposal.

The same risks are encountered for transportation to shore. This alternative would also require adequate land disposal facilities. These materials from onshore drilling operations are now

exempt from control by EPA under the Resource Conservation and Recovery Act of 1976 (RCRA). However, EPA is responsible for evaluating the environmental impact of the land disposal of muds and cuttings.

Another method of overboard discharge of drilling muds and cuttings in sensitive areas is release through pipes well below the water surface. This minimizes the transport and the chance for environmental damage. In some OCS sensitive areas, shunting is required. There is debate about the effectiveness of this method, due to the rapid dilution once the discharge enters the water during the surface discharge procedures. Furthermore, underwater release costs upwards of $100,000 per well and creates some safety problems during heavy storms.

C. Spill Incidents

Protection of the offshore marine environment requires that equipment be properly maintained. In addition, state and federal regulations (e.g., USGS-OCS Orders) require that facilities be maintained and inspected. Oil spills, should they occur, must be reported to the USGS and the National Response Center. Furthermore, the USGS requires that operators prepare an Oil Spill Contingency Plan. This plan must contain a description of procedures, personnel, and equipment that will be used to clean up and prevent the spread of any pollution resulting from an oil spill There are at least 93 cooperatives for maintaining oil spill containment and cleanup equipment at strategic points along the coast of the United States.

D. Fate and Effects of Drilling Fluid Discharged to Coastal and Offshore Waters

1. Fate of Discharged Drilling Fluid and Cuttings

a. Amount of Fluid and Cuttings Discharged

Most oil and gas wells have diameters that diminish in stages with their depth. Usually, each segment is lined with steel casing that is anchored to the borehole wall with cement. The casing prevents collapse of the hole and the uncontrolled flow of fluids in or out of the wellbore.

Table 28 shows the typical hole sizes for 10,000- and 20,000-foot wells, and the volumes of rock removed in drilling each segment. Note that doubling the depth triples the amount of rock removed, and that the increase occurs mainly in the shallow part of the well.[65] During drilling, these cuttings are sprayed with clean water as they move over the vibrating shaker screens in order to wash off the mud. Then they are discharged near the water surface, where they fall in a pattern surrounding the discharge point, depending upon water current and particle size. The larger particles fall close to the source, while finer cuttings and solids are distributed to greater distances. In the Gulf of Mexico, the pattern was observed and photographed.[66] In 26 meters of water

TABLE 28

Hole Size and Casing Program for a Deep Well

Approximate Interval Drilled (ft)*	Hole Size (in.)	Casing Size (in.)	Cased Interval (ft)	Volume Interval Drilled (cu ft)	(bbl)
			For 20,000-Foot Well		
0-500	36	30	0-500	3,534	629
500-1,000	26	20	0-1,000	1,859	331
1,000-3,000	17-1/2	13-3/8	0-3,000	3,369	600
3,000-12,000	12-1/4	9-5/8	0-12,000	7,428	1,322
12,000-15,000	8-3/8	7-5/8†	12,000-15,000	1,157	206
15,000-20,000	6-1/2	5-1/2†	15,000-20,000	1,162	207
			Total	18,509	3,295
			For 10,000-Foot Well		
0-100§	--	20	--	--	--
0-500	17-1/2	13-3/8	0-500	835	149
500-3,000	12-1/4	9-5/8	0-3,000	2,046	365
3,000-10,000	8-3/4	--	--	2,923	520
			Total	5,804	1,034

*These depth intervals may be decreased or increased.

†Liner.

§Conductor pipe, pile drive to normal refusal.

SOURCE: Monaghan et al., "Environmental Aspects of Drilling Muds and Cuttings from Oil and Gas Operations in Offshore and Coastal Waters," Proceedings, Offshore Technology Conference, 1977.

and slow currents, new cutting piles were found one meter high and 50 meters in diameter. The areal outlines were circular, elongated, or starburst, depending upon the currents.

b. Fate of Drill Cuttings

In areas with strong tidal currents, cuttings become widely dispersed quickly. In the lower Cook Inlet, underwater television examination of the local sea floor immediately after drilling showed no accumulation of cuttings, and barium levels were only slightly elevated.[67] Bottom samples indicated that the sea floor was sufficiently mobile to mix cuttings to a depth of at least 12 centimeters at the end of drilling. Less than 10 percent by weight of cuttings was found in 0.5-centimeter sections of these samples.

Storms eventually disperse cutting piles in relatively shallow water. In the Gulf of Mexico, no cuttings were found beneath production platforms in approximately 20 meters of water after 10 to 15 years.[68,69] In two California studies, six-meter-high piles of cuttings were found under two platforms.[70] These cuttings were more resistant to weathering, breakdown, and dispersal than Gulf of Mexico sediments.

Similar dispersions of drill cuttings were observed during the drilling of a well on the OCS of southern California.[71] Submarine reconnaissance, sediment grab samples, and calculations of average current velocity and wave energy substantiated the absence of visible cuttings. Some cuttings were identified in mineralogical and microscopic analyses of the post-drilling sediments collected near the points of discharge.

c. Fate of Drilling Fluid

During drilling, extra mud is held in reserve in the circulation tank. The reserve is used as the volume of the wellbore increases. However, sometimes the drilling fluid must be changed to cope with increased viscosity and changing composition as the formations being drilled change. Thus, bulk discharges of drilling fluid are made periodically. This also occurs during cementing operations, when the annulus between the casing and wellbore is displaced by cement. Finally, there is a single discharge of surplus drilling fluid when the well is completed. Periodic discharges during drilling are normally from 100 to 300 barrels, but they can be as high as 2,000 barrels, depending upon the depth of the well.

(i) First Studies of Drilling Fluid Discharges

When drilling mud is discharged, two plumes are formed. The lower plume consists of cuttings with some adhering drill fluids; the upper plume contains silt and clay that move with the upper water currents. Concentrations of solids in mud discharges range from 20 to 30 percent, and the total volume of mud discharged over the life of a well ranges from 1,500 to 5,000 cubic meters (10,000 to 30,000 barrels).

Early studies demonstrated the rapid dilution of the drilling fluid surface plume.[72,73] Samples of seawater were collected up and down current from a platform drilling in 60 feet of water in the Gulf of Mexico.[74] Suspended solids totaled 350,000 mg/l in the reservoir tank, 278 mg/l at the water surface above the discharge point, 41 mg/l at the surface 100 meters down current, and 5.5 mg/l at the surface 200 meters down current, compared with 5.2 mg/l measured at the surface 100 meters up current. Water samples collected at a 10 meter depth and 100 and 200 meters down current measured 1.5 and 1.1 mg/l, respectively.

Similar observations were made for 34 water samples collected near the surface, at mid-depth, and near the bottom up to 200 meters from a drilling well.[75] The solids contents ranged from

4 to 80 ppm (mg/l). Alkalinity was constant in all samples.[76] Chromium in seven of the 34 samples ranged from 0.01 (the detection limit) to 0.52 ppm. These concentrations soon diluted to undetectable amounts, reaching nearly 10,000-fold dilution while moving 100 meters down current.

These initial studies have since been substantiated by a number of more exhaustive investigations, four of which are discussed below.

(ii) Tanner Bank Study (Offshore Southern California)

The Tanner Bank study was conducted from January through March 1977, during the drilling of a shelf exploratory well some 160 kilometers west of Los Angeles, in 60 meters of water.[77,78] The drilling fluid surface plume was investigated during normal drilling operations and during bulk discharges (i.e., 120 cubic meters per hour or 750 barrels per hour). Suspended solids concentrations decreased from a range of 250,000 to 328,000 ppm just outside the discharge pipes, to 25 ppm 74 meters down current. Background levels were reached 1,000 meters down current.

Trace metal concentrations were elevated in samples collected within 3 meters of the discharge. At 100 to 150 meters, these concentrations approached background levels for all but one bulk discharge. These metals included barium (as barium sulfate), chromium (as trivalent chromium), and lead (from pipe thread dope used in the drill string). All other properties studied (pH, temperatures, dissolved oxygen, and salinity) reached background at less than 100 meters down current.

(iii) Lower Cook Inlet (Alaska) Study

This study was conducted in the summer of 1977, during the drilling of a stratigraphic test well 56 kilometers west of Homer, in 65 meters of water. The drilling fluid dispersion studies included dilution tests using a fluorescent dye tracer.[79] A dilution of 10,000 to one within 100 meters of the discharge point was attributed in part to turbulent flow induced by the drilling vessel's underwater structure.

(iv) High-Volume Discharges (Gulf of Mexico)

Two bulk discharges were studied in 23 meters of water in the Gulf of Mexico: 250 barrels of mud at a rate of 275 barrels per hour, and 389 barrels at a rate of 1,000 barrels per hour. Water samples were taken at the bottom, top, and most dense portion of the discharge plume, using a rosette sampling array suspended from a helicopter. Suspended solids and metal tracer concentrations in the plume reached background levels about 500 meters from the discharge point during the 275 barrels per hour test, and about 1,000 meters from the discharge during the 1,000 barrels per hour test. Table 29 shows the marked decrease with distance.

TABLE 29

Suspended Solids Concentration and Transmittance vs. Distance During High Rate Discharge

Distance from Source (Meters)	Depth (Meters)	Solids Concentration (mg/l)*	Transmittance (%)
		275 Barrels/Hour -- 250 Barrels Discharged	
0 (whole mud)	--	1,430,000	--
6	8	14,800	--
45	11	34	2
138	9	8.5	56
250	9	7.0	48
364	9	1.2	37
625	9	0.9	71
Background		0.3-1.9	76-85
		1,000 Barrels/Hour -- 389 Barrels Discharged	
0 (whole mud)	--	1,430,000	--
45	11	885	0
51	12	727	0
152	11	50.5	2
375	16	24.1	4
498	14	8.6	23
777	13	4.1	21
878	2	1.2	71
957	12	0.83	76
1,470	11	2.2	82
1,550	9	1.1	82
Background		0.4-1.1	80-70

*Maximum concentration and minimum transmittance measured at noted distances downcurrent of the source.

SOURCE: Ayers et al., "An Environmental Study to Assess the Effects of Drilling Fluids on Water Quality Parameters During High Rate, High Volume Discharges to the Ocean," In Proceedings of the Symposium: Research on the Environmental Fate and Effects of Drilling Fluids and Cuttings, January 21-24, 1980.

(v) Mid-Atlantic Bight Study

Drilling fluid discharges were monitored at a well drilled 156 kilometers east of Atlantic City, New Jersey, in 120 meters of water. Because bottom currents in this area are weak, the sea floor can be characterized as a low-energy environment. Discharges included 752 metric tons of barite, 1,409 metric tons of low-gravity solids (bentonite plus natural formation drilling solids), and 95 metric tons of organic chemicals (chrome lignosulfonate, lignite, and cellulose polymer). Also monitored were two bulk mud discharges, of 500 and 275 barrels per hour.[80]

As in other studies the discharge formed two plumes: a lower plume containing the bulk of the solids that descended rapidly; and an upper plume generated by turbulent mixing with seawater, a diffusing cloud in the upper water column that drifted with the current. The suspended solids concentration in this plume had dropped by a factor of 10,000 at 100 meters down current, and reached background at 350 to 650 meters down current. Transmittance values reached background at 800 to 1,000 meters. During both discharges, background values were measured in the discharge plumes for dissolved oxygen, pH, salinity, and temperature.

To assess sources of trace metals in drilling mud discharges, chromium, cadmium, lead, mercury, nickel, vanadium, and zinc were measured in the major drilling fluid additives (barite, bentonite, chrome lignosulfonate, and lignite). Trace metal concentrations in the major additives were all below detectable limits, except for zinc in bentonite and organic chemicals and chromium in chrome lignosulfonate. This was a major source of chromium in all discharges. The discharged drill cuttings contained some cadmium, mercury, nickel, and vanadium. It appears that these were derived from the formation drilled, because the amounts of nickel and vanadium in the mud additives were considerably lower than those in the discharged solids. The additives contained some cadmium and mercury, but the concentrations were so close to the limit of detection that interpretation was difficult.

2. Effects of Drilling Fluids and Cuttings

a. Bioassays of Drilling Mud Components

The standard laboratory bioassay consists of exposing test organisms in aquaria to varying concentrations of toxicants, usually for 96 hours. Based on the mortality rates of the organisms, the concentration to kill 50 percent of the organisms is expressed as LC_{50}.[81]

Most of the major drilling mud components (bentonite and barite) are natural minerals ground to a fine powder. They are insoluble and inert, and show little or no toxicity to organisms.

Most of the other inorganic chemicals commonly used in muds can be considered nontoxic, even though they may show toxicity as pure chemicals. Sodium carbonate, sodium bicarbonate, and sodium acid

pyrophosphate are added to react with calcium ions that enter the mud. These chemical reactions form the inert solids calcium carbonate or calcium phosphate. Sodium hydroxide (NaOH) is added in considerable quantity to control pH. At pH 10 (usual for lignosulfonate mud) the hydroxyl ion concentration is only 1.7 ppm, equivalent to about 4 ppm of NaOH. Upon discharge, the small amount of unreacted NaOH immediately dilutes and/or further reacts with seawater constituents and is neutralized. Thus, bioassay results showing that 100 ppm NaOH alone is toxic are not pertinent to muds.

Of the materials added to drilling muds in appreciable quantities, the toxicities of ferrochrome and chrome lignosulfonates appeared to be the highest. Ninety-six-hour LC_{50} values for aqueous solutions of these compounds range from 460 to 1,220 ppm for test organisms, including white shrimp, rainbow trout, and sailfin mollies. The ferrochrome or chrome lignosulfonate in drilling fluids may be absorbed into clays and barite, reducing their availability to plants or animals.

Sometimes it is necessary to use biocides in drilling fluids. These products, by design, range from toxic to very toxic, but are used in very low concentrations. When they are discharged, dilution quickly lowers concentrations to biodegradable levels.[82] Because whole drilling fluids and not components are discharged, bioassay tests conducted on whole drilling fluids are more useful for predicting environmental impacts than are tests on individual components. In general, whole drilling fluids are less toxic than would be calculated from individual components. This is due to neutralization reactions between components and adsorption of soluble components and ions onto clay particles.

b. Bioassays of Whole Drilling Fluids

A large number of laboratory bioassays have been conducted on whole muds from drilling wells.[83-92] These studies have tested drilling fluid toxicities on more than 50 species from 11 groups: plankton, copepods, isopods, amphipods, gastropods, decapods, bivalves, echinoderms, mysids, polychaetes, and finfish. The number and variety of species tested is a sufficiently representative cross-section of species sensitivities to ensure that unexpected toxicities will not occur. Toxicity tests using the shrimp or mysids comprised over 20 percent of the total, and larval or juvenile animals were used in over 20 percent of all tests. Many of the larval tests were also performed on the most sensitive species. For example, about 35 percent of shrimp tests were conducted on larvae, as were over 40 percent on lobster and 75 percent on mysids. With finfish, over 35 percent were done on juveniles. Therefore, the estimates of biological impact were biased toward the sensitive species and sensitive life stages.

Over 350 toxicity tests were conducted on approximately 55 drilling fluids. The mean 96-hr LC_{50} value for these tests was approximately 150,000 ppm. The values ranged from 360 to over 700,000 ppm, but very few were below 1,000 ppm. Low 96-hr LC_{50}

values of 360 to 739 ppm were obtained using a sensitive shrimp and a drilling fluid from a Mobile Bay, Alabama, well.[93] Since this drilling fluid was known to be toxic, it was injected into a disposal well and the solids were brought ashore for disposal in a solids waste disposal site.

Most of the extensive bioassay data show that in almost all cases the fluids are relatively nontoxic.

c. Water Column Effects

The drilling fluid fines disperse quickly in a down current plume. These offshore tests have shown that 10,000-to-1 dispersion occurs in less than 100 meters. In that distance, drilling fluids containing from 300,000 to 600,000 ppm of dissolved solids would dilute to 30 to 60 ppm. Further, the exposure time to organisms in the near-surface waters (down to 15 to 20 meters) is only 3 minutes in a 1-knot current and 11 minutes in a 0.3-knot current.

The 10,000-to-1 dispersion within 100 meters was based on bulk mud discharges at high rates, from 250 to 1,000 barrels per hour. At normally lower rates of discharge, 10,000-to-1 dispersion is obtained in lesser distances from the discharge point.

For such discharges, adverse biological effects would occur only to planktonic organisms that moved with the water containing the dispersing drilling fluids. The volume of water in which exposure would occur to such organisms would be relatively small and the exposure time short. Therefore, based upon laboratory bioassays indicating that almost all drilling fluids are relatively nontoxic under bioassay test conditions, one would conclude that the biological community would suffer no ill effects. Even discharge of the very toxic drilling fluids from the Mobile Bay well would be unlikely to have caused adverse biological effects. Nontoxic concentrations (30 to 60 ppm) would have existed for a few minutes, compared with a four-day bioassay requiring from 360 to 710 ppm to kill 50 percent of a sensitive species.

Comparison tests have indicated that about 90 percent of the toxicity resides in the filtrates. Therefore, most of the toxicity is in the upper plume carrying the soluble constituents and fines. This analysis of the data shows that even the most toxic fraction of drilling fluids has little or no effect on the marine environment.

In a field test of toxicity, pink salmon fry, shrimp, and hermit crabs were placed in boxes and suspended down current from drilling fluid discharges.[94] No mortalities were recorded that could be related to the discharge plume. Any such effect would have been inconsistent with the above analysis.

Dispersing mud plumes can diminish the photosynthetic activity of phytoplankton by reducing light transmittance. The effect is not proportional to the available light, however, because photosynthesis can also occur in scattered light. In any event, the actual effect of these plumes on photosynthesis is very small when

day/night variation, cloud cover, and seasonal changes in water transparency due to coastal runoff and primary productivity are considered. Plume volumes are small (a few thousand square meters). Their short duration, rapid dispersion, and brief contact time with photosynthetic organisms minimizes their impact.

d. Benthic Effects of Drill Solids

The speed with which cuttings and solids from the drilling fluid settle depends upon their density and particle size. When current energy is low, the solids settle near the discharge point, but in high energy locations they are rapidly dispersed or reworked by bottom currents.

(i) Possible Toxicity to Benthic Organisms

About 90 percent of the drilling mud toxicity resides in the surface plumes that drift away from discharge points and rapidly disperse. Therefore, the settled materials are relatively nontoxic compared with whole drilling fluids. The settling particles are washed as they pass through the water column, and the only remaining toxicity is from adherence of filtrate to cuttings and the larger mud solids. Adverse toxic effects to benthic organisms have therefore been overstated when whole drilling fluid toxicities are applied to the drilling solids in bottom sediments. For instance, barite, a nontoxic, high density constituent is preferentially deposited and certainly does not possess the toxicity of whole drilling fluids. The drill cuttings themselves have never been considered toxic, but have not been tested in bioassays. Solids deposited on the bottom are unlikely to have a direct toxic effect on benthic organisms.

(ii) Possible Incorporation of Metals into the Food Chain and Effects on Other Organisms, Including Man

In the relatively quiet waters of the mid-Atlantic Bight, drill cuttings and solids were found to accumulate near the platform.[95] Sediment samples were analyzed for arsenic, barium, cadmium, chromium, copper, mercury, nickel, lead, vanadium, and zinc. Pre- and post-analysis of sediments showed a nonsignificant increase in barium. Significant increases were observed in lead, nickel, vanadium, and zinc, but significant decreases in cadmium and chromium were also apparent. These changes may have been associated with waters and contained sediments already present from the dump area outside New York harbor.

Tissue analysis on mollusks showed significant increases in barium and mercury and significant decreases for arsenic, cadmium, and copper. Polychaetes showed a major increase in chromium and a major decrease in copper. Brittle stars showed significant increases in barium, lead, mercury, and vanadium and significant decreases in copper and nickel. There was no correlation between where the organisms were collected and the metals content of the sediments.

In a study conducted near a number of offshore platforms, concentration gradients of barium, cadmium, chromium, copper, lead, and zinc in surficial sediments decreased with distance from some platforms in the Gulf of Mexico.[96] Metal concentrations in muscle tissues of commercially important species (brown shrimp, croaker, sheepshead, and spadefish) did not in general show significantly higher metal concentrations than similar organisms from other areas of the Gulf of Mexico. However, concentrations of copper and iron were higher in local sheepshead and spadefish muscle, and nickel was higher in sheepshead.

Field studies have shown limited, if any, bio-availability of metals from drilling fluid discharges. In laboratory studies, the marsh clam and the Pacific oyster were exposed to four used drilling muds, then analyzed the tissues for chromium, lead, and zinc.[97] The clams accumulated significant amounts of chromium in four days. However, most of the chromium was released within 24 hours when the clams were returned to clean seawater. This indicated that much of the chromium accumulated was unassimilated material in the digestive tract or on the gills. When the clams were exposed to the drilling fluid filtrate for 16 days, they accumulated a mean of 19 ppm chromium. Returned to seawater, they released approximately half in 24 hours. When exposed to mud filtrate for two weeks, oyster spat showed little or no net accumulations of chromium, lead, or zinc. These workers concluded that heavy metals from typical used drilling muds have limited bio-availability to marine bivalve mollusks during short-term exposure.

These studies demonstrate the low bio-availability of most constitutents in drilling muds. Studies on the inputs and accumulation of metals (barium, cadmium, chromium, copper, lead, mercury, nickel, and zinc) show that the large quantities introduced into marine waters and sediments have not been concentrated in the food web.

Tissue samples from animals collected below oil platforms off Santa Barbara, California, do not show elevated levels of trace metals. Mercury, which under certain conditions has been shown to be concentrated from water and food by marine organisms, does not seem to be bio-accumulated excessively from waters and sediments off California. For example, municipal wastewaters introduce an estimated 3 metric tons of mercury per year into the near offshore waters of southern California. Other sources bring the total to about 17 metric tons per year. Samples from sediment traps placed off one major Los Angeles area sanitary outfall collected as high as 9.5 ppm of mercury (dry weight). Sediments taken from the continental shelf contained as much as 5 ppm, yet animal tissues from these areas did not contain elevated levels of mercury. Metals from drilling fluid discharges are minor compared with those from other sources. Thus, the lack of evidence of bio-availability from drilling fluids and little or no bio-accumulation of metals by marine organisms suggests that the effects of metals from this source are minimal.

e. Physical Effects of Drill Solids

Physical smothering of benthic organisms usually creates only a minor risk. If the area is one of high energy, the material will be widely dispersed; and in a low-energy area, the effect is localized near the discharge point.

The discharge of mud and cuttings from a Gulf of Mexico well was monitored and no adverse effects on fish or other organisms in the water column were observed.[98] Crabs and gastropods were noted digging in the cuttings pile, while groupers and red snappers were nosing in the pile, undisturbed by the chips still falling through the water. At a number of locations, cutting piles were observed that were typically about 1 meter high (when new) and 50 meters in diameter. Their aereal outlines were circular, elongate, or starburst, depending upon bottom currents.

During drilling of the well in the mid-Atlantic Bight, drilling discharges did have an effect on the benthic community.[99] A zone of discharge accumulations (primarily formation clays) was observed close to the well site, and elevated clay levels were detected as far as 800 meters from the site. Fish and crabs increase substantially in the vicinity, probably attracted by the increased micro-relief afforded by the cuttings accumulations, as well as by the increased availability of food.

High densities of sand stars were observed near the well site, apparently associated with the accumulations of mussels falling from the drilling rig, anchor chains, and work boats. Reductions in abundance of the macrobenthos farther from the well site were attributed in part to increased predation by fish and crabs, and in part to the increased clay content of the sediments.

No change in species diversity was observed in the pre- and post-drilling macrobenthic samples. However, several possibilities are suggested to account for observed reductions in abundances of some macrobenthos, relating to settling and settled clay particles. A change in substrate composition (e.g., from silts and sand to clay) may restrict the recruitment of certain benthic larvae. However, as bottom materials are reworked and resuspended and new natural material is deposited, conditions are expected to gradually revert to those of the pre-drilling period.

Changes in the substrate can be either detrimental or beneficial, depending upon one's point of view. Alteration of the sediments may change the benthic association controlled by sediment composition. However, the displaced organisms are replaced by other organisms. There have been no indications that drilling discharges have resulted in either a dead area or in the benthos becoming undesirable. Any observed changes have been very localized.

In southern California, replacement of the bottom mud with cuttings that are quite resistant to breakdown (i.e., with a solid

substrate) results in a much more varied benthic community and increased biomass near the platforms. This increased food supply has attracted fish. For example, one study found 20 to 50 times more fish under oil platforms than over soft-bottom control regions nearby.[100]

Cuttings and associated material from sedimentary rocks are very similar to the eroded sediments that have always entered the ocean. Table 30 lists some of the sources. Rivers contribute very large quantities. Figure 26 shows sediment discharged from the Mississippi River as of January 16, 1973. The flow and sediment discharge is even higher at other times of the year, particularly in the spring months. During floods in 1969, an estimated 83 million metric tons of sediment entered the Santa Barbara channel. This covered the bottom with a layer varying from 10 centimeters (4 inches) thick off Ventura to about 1 centimenter thick (0.5 inches) off Goleta, some 50 kilometers (30 miles) to the west. Neither the high rate of sedimentation nor the accompanying turbidity had a major effect on the biological productivity of the area.[101]

TABLE 30

Sediment Discharged to Marine Environment
(Million Tons Per Year)

Rivers -- World	20,000
Mississippi	344
Colorado	149
Eel, N. California	33
Santa Clara (one day)	22
Marine Sediment Transport	Large
Dredging -- Mostly Harbor and Channel, 1968	38.5
Bottom Fishing Trawls	Unknown
Drilling -- Cuttings and Drilling Fluid Solids, 1,000 Wells/Year	1.0

SOURCE: McAuliffe, C. D., "Environmental Aspects of OCS Petroleum Development," 1976.

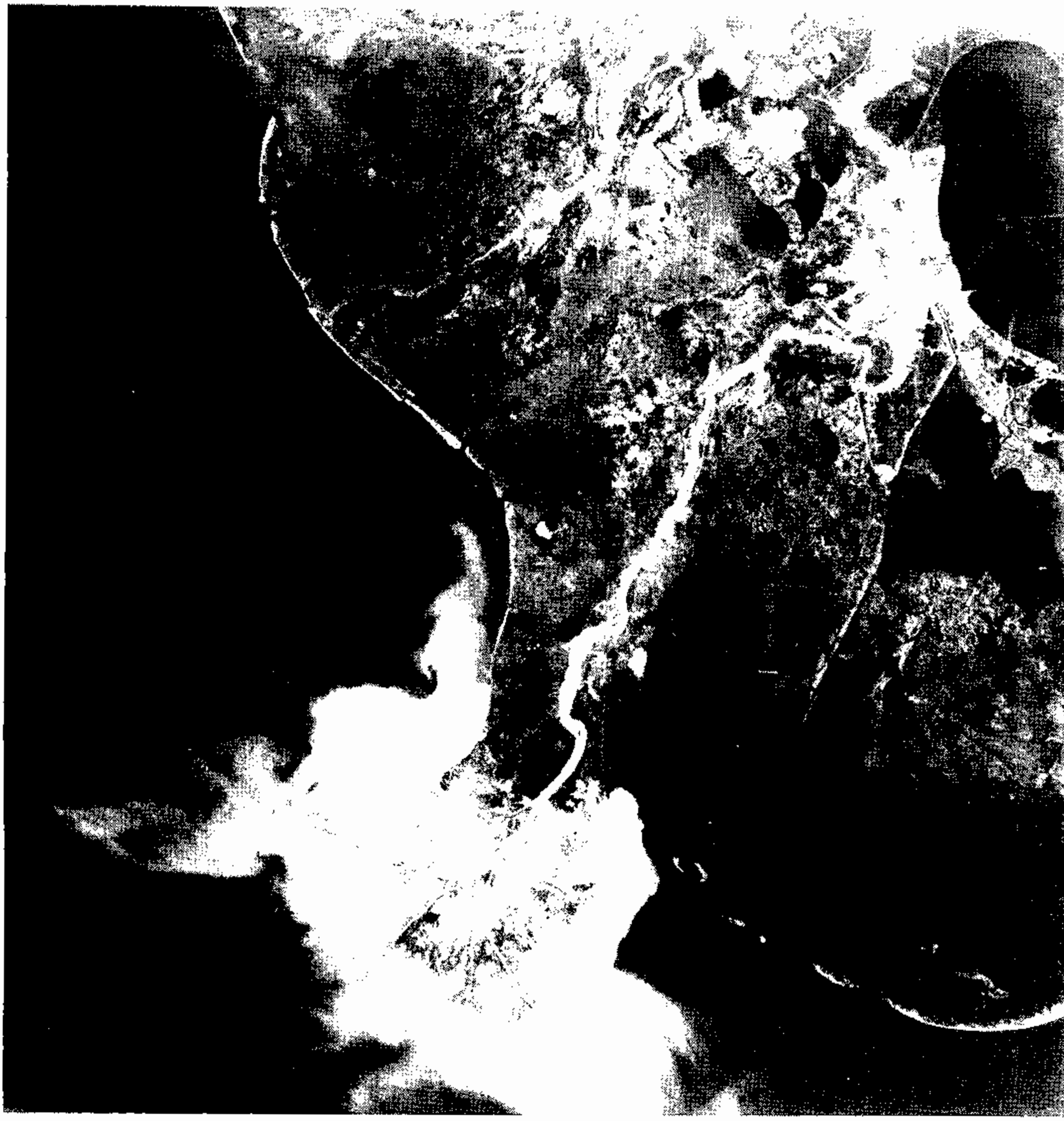


Figure 26. Sediment Discharge of Mississippi River—January 16, 1973.

SOURCE: McAuliffe and Palmer, *Environmental Aspects of Offshore Disposal of Drilling Fluids and Cuttings*, 1976.

Near-shore and bottom currents, particularly during storms, resuspend and transport large amounts of sediments. Bottom-fishing trawls also disturb and resuspend large amounts of sediments. The actual quantities are not known, but they may be large when considering the number of these trawls. Flights off the East Coast have shown large sediment plumes following fishing vessels pulling bottom trawls. Off southern California, trawl marks remain in the bottom sediments.

Other large man-made contributions are from dredging, mostly from channels and harbors. This dredged spoil is discharged into U.S. coastal waters.

The data in Table 30 show that the contribution of solids from drilling wells is extremely small, and the relative physical effects on the marine environment are inconsequential.

f. Field Studies of Chronic Effects of Drilling Discharges

Researchers made observations under a platform drilling off Louisiana.[102] Encrusting forms that grow on the platform members appeared to be unaffected by the discharges. Barnacles were living not only on and beneath the drilling fluid discharge pipe, but actually inside it, where they would be most affected by the discharges.

Another researcher studied the "fouling" community on a drilling rig, exposed to long-term, intermittent drilling discharges.[103] He systematically collected data on the presence or absence of species for macrobenthic algae and inverbrates for mud-free and mud-exposed sites on four horizontal support pontoons beneath the rig. Analysis indicated that each of the four pontoons maintained a significantly different community. Those on the two mud-exposed pontoons more closely resembled each other than did those relatively uninfluenced by mud. The pontoon directly beneath the mud discharge displayed the greater community differences, though only within 10 meters of the discharge pipe. These differences appeared to be predominantly accounted for by the change from a hard metal substrate to a mud (i.e., sedimentary) substrate. The study concluded that chronic exposure to normal drilling discharges caused only a very local effect on the fouling community.

III. Environmental Expenditures

The API annual cost survey reports water-pollution-related capital expenditures for the exploration and production segment of the industry of $316 million for 1980. This represents an increase of $76 million over 1979. The 10-year cumulative total stands at $1,505 million. Administrative, operating, and maintenance expenditures amount to $215 million for 1980, an increase of $42 million over 1979. The 10-year cumulative total for operating and maintenance stands at $1,194 million.

WASTE MANAGEMENT

I. Background

The major wastes generated by the exploration and production operations are produced waters, waste drilling muds, and drill cuttings. Other materials that may be regulated as hazardous wastes after use or where excesses occur are corrosion inhibitors, emulsion breakers, biocides, cleaning agents, solvents, lube oils, acids, and cement. Four criteria (corrosivity, ignitability, reactivity, and toxicity) have been established by RCRA regulations to determine if a waste is hazardous.

In October 1980, Congress amended RCRA to exempt drilling muds, produced waters, and other wastes associated with exploration, drilling, and production for two years. Congress directed EPA to do an in-depth study of waste drilling muds, produced waters, and associated waste from the exploration and production of oil and gas and geothermal energy. EPA is to report to Congress by October 21, 1982. Six months after submission of its study to Congress, EPA must, after public hearings and opportunity for comment, either promulgate regulations or determine that regulations are unwarranted. Any regulations proposed by EPA must be submitted to both houses of Congress and shall not be effective unless authorized by an Act of Congress.

The RCRA exemption was granted because EPA admitted that it possessed very little information on the composition, characteristics, or degree of hazard posed by these wastes. EPA further acknowledged that these wastes occur in high volume, are generally low in toxicity, and that potential hazards posed by these wastes are relatively low. An overriding consideration in granting the exemption was Congress' desire to discourage regulations that would unduly restrict domestic energy and natural resource production.[104]

In the unlikely event that the exemption for drilling muds, produced waters, and associated waste is lifted and oil and gas industry exploration activities must comply with the EPA's proposed RCRA regulations, the costs the first year to comply with the full regulations could be as high as $31 billion (in constant 1978 dollars), and an additional $3.3 billion per year in direct operating and maintenance costs based upon the regulatory program proposed in December 1978.[105]

Even if Congress continues the RCRA exemption for exploration and production or chooses to regulate these wastes in a relatively modest manner, there could be continuing problems with the disposal of hazardous wastes due to the shortage of approved disposal sites. The increasing concerns of state and local governments with disposal sites could significantly impact future levels of oil and gas development.

II. Research

In 1974, API funded a comprehensive research project entitled "Effects of Drilling Fluid Components and Mixtures on Plants and Soils," which was performed at Utah State University.[106] This research spanned six years of testing three agricultural crops, six different soil regimes, 31 separate drilling mud components, and seven different drilling mud formulations. The major conclusion drawn is that any short-term problems of spreading and mixing drilling mud waste into soils can be eliminated through proper treatment; thus there should not be any long-term detrimental effects of the muds themselves.

API has funded additional research entitled "Plant Uptake and Accumulation of Metals Derived from Drilling Fluids," which is currently being performed at Purdue University.[107] Phase I of this research in greenhouses was completed after testing three drilling mud formulations on two fertile soils with two agricultural plants. Test results thus far have indicated that cadmium, zinc, copper, arsenic, and lead were partially available for uptake and directly related to concentration; and mercury, chromium, and barium were not available for uptake. Phase II of this project, consisting of field tests, is under way.

Another, more extensive, nationwide survey and study is being conducted by API. This study is designed to measure the effects that drilling mud waste, produced waters, and associated waste may have on human health and the environment. The survey is being conducted at existing sites used for drilling and producing operations. The study started in the spring of 1980 and will cover eight sites in various hydrologic regimes across the United States; it is scheduled to be completed in May 1982. Phase I of the study was completed March 25, 1981, and shows favorable compatibility of current disposal practices to human health and the environment.[108]

The API study also indicates that wastes associated with exploration, production, and natural gas processing facilities are of very low volume and are site specific. The pilot study shows no plant uptake of heavy metals and no migration of heavy metals through underground water aquifers from these holding pits. The study does indicate low concentrations of chlorides from salt water migrating from the pits to the underground water aquifer. The pit being used in this pilot study has a chloride concentration of 150,000 ppm. On the second underground water observation well 75 feet down stream from the emergency pit, the water contains 450 ppm chlorides. Additional work is in progress to drill additional down-dip underground aquifer observation wells to see at what point dilution of the salt concentration is back to fresh water baseline.

The studies indicate a need for EPA to adopt a degree of hazard for the wastes the Agency is attempting to classify.[109-113] The degree of hazard should consider bulk volumes and not just the

Table 31

Environmental Expenditures in Exploration and Production -- 1971-1980
(Millions of Dollars)

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	Total 1971-1980
Capital Expenditures											
Air	$15	$17	$14	$27	$59	$85	$68	$59	$55	$123	$522
Water	82	68	62	92	117	135	187	206	240	316	1,505
Land and Other	13	22	27	38	57	70	54	59	63	120	523
Subtotal	$110	$107	$103	$157	$233	$290	$309	$324	$358	$559	$2,550
Administrative, Operating, & Maintenance Expenditures											
Air	$8	$8	$12	$15	$20	$21	$28	$32	$35	$62	$241
Water	84	66	69	90	87	115	141	154	173	215	1,194
Land and Other	16	16	20	24	29	27	31	38	36	52	289
Subtotal	$108	$90	$101	$129	$136	$163	$200	$224	$244	$329	$1,724
Total	$218	$197	$204	$186	$369	$453	$509	$548	$602	$888	$4,274

SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry, 1971-1980*, 1981.

classification of a hazardous component that may be in the total waste stream.

ENVIRONMENTAL EXPENDITURES

The exploration and production segment of the petroleum industry has a consistent and sustained record for environmental expenditures as shown by the data in Table 31. Over the past decade this segment of the industry has invested over $2.5 billion in environmental facilities and $1.7 billion in operating the facilities. The total expenditures of $4.274 billion spent by exploration and production operations represents about 20 percent of the total pollution control expenditures by the industry.

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[1]In offshore Alaska USGS included resources that are recoverable only if technology permits their exploitation beneath Arctic pack ice.

[2]The Public Land Law Review Commission was created by an act of Congress on September 19, 1964 (PL 88-606). Congress declared that because of the lack of correlation between existing public land laws and because the public lands were administered by several agencies, the laws might be inadequate to meet the current and future needs of the American people. Congress charged the commission to undertake a "comprehensive review of those laws and regulations...and to determine whether and to what extent revisions thereof are necessary." The final report of the Commission was released in June 1970.

[3]Ibid.

[4]The concepts of *de jure* (by law) and *de facto* (in fact) withdrawals were introduced by Gary Bennethum and L. Courtland Lee in a paper entitled "Is Our Account Overdrawn?" (*Mining Congress Journal*, Sept. 1975). Withdrawals made by Congress and the Executive Branch under explicit withdrawal from the operation of specific land laws such as the mineral laws, can be considered *de jure*, whereas other actions (or even failures to act) may so restrict access to lands that they are withdrawn in fact (*de facto*). Although these concepts have practical significance, they are difficult to apply to quantitative definitions of the *degree* to which lands are totally withdrawn or restricted from access to some extent. The U.S. Department of the Interior's *Final Report of the Task Force on the Availability of Federally Owned Mineral Lands*, 1977, and the Congressional Office of Technology Assessment study entitled *Management of Fuel and Nonfuel Minerals in Federal Land*, 1979, have chosen bases dependent instead on degree of restriction, as determined by the extent of restriction present in land-use plans, legislation, policies, or other indicators.

[5]16 U.S.C. §§1901-1912 (1976), Public Law No. 94-429. The Act provides for regulation of "all activities resulting from the exercise of valid existing mineral rights on patented or unpatented mining claims within any area of the National Park System" by the Secretary of the Interior, and repealed the application of mining laws to areas of the National Park System.

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CHAPTER THREE

REFINING

INDUSTRY OPERATIONS

ENVIRONMENTAL CONSIDERATIONS

CHAPTER THREE

REFINING

INDUSTRY OPERATIONS

INTRODUCTION

From the 1860's until 1920, refining operations were generally limited to crude oil distillation for the production of kerosine. The petroleum refining industry increased in processing capacity from 11,680 barrels per day in 1865 to 142,465 barrels per day in 1900. By 1960, capacity stood at 9.9 million barrels per day. Capacity nearly doubled over the next 20 years; by 1980 operating capacity was 17.6 million barrels per day.[1]

In the United States, refineries' crude oil input varies from 190 barrels per day to 640,000 barrels per day. The simplest refineries "top" the crude oil and are usually limited to atmospheric distillation and, in some cases, vacuum distillation (Figure 27). These plants produce only a few products, such as naphthas, distillates, residual fuels, and asphalts. More complex refineries have process units such as cracking, alkylation, reforming, isomerization, hydrotreating, and lubricant processing (Figure 28), producing a wide range of products, including gasolines, low-sulfur fuel oils, lubricants, petrochemicals, and petrochemical feedstocks.

Crude oil is a mixture of thousands of different hydrocarbons with a wide range of boiling points. In addition, crude oil contains compounds with various amounts of sulfur, nitrogen, and oxygen, plus salt, trace metals, and water. Crude oil can range from an almost clear liquid, similar to gasoline, to a pitch, tar-like material that is viscous and must be heated before it will flow through a pipeline. Crude oil is typically designated as either sweet or sour, and either light or heavy. Generally, sweet crude oil contains 0.5 weight percent or less total sulfur, and sour crude oil contains more than 0.5 weight percent sulfur. Light crude oil is defined as having an API gravity greater than 25°, and heavy crude oil has a gravity of 25° or less.

The initial refining process separates crude oil into boiling range fractions. These fractions are then processed by cracking the large hydrocarbon molecules into smaller ones. The structure of some of these molecules is rearranged and others are joined in different combinations to provide the desired components for blending into finished products. This takes place in a number of refinery process units, each with a specific purpose, integrated into a processing sequence. The type and number of refinery process units in a given plant depends upon the type of crude oil to be processed, product requirements, and economic factors such as crude oil costs, product values, and availability and cost of utilities and equipment. The type and size of processing units thus varies greatly. Theoretically, any petroleum or petrochemical product can be manufactured from any type of crude oil.

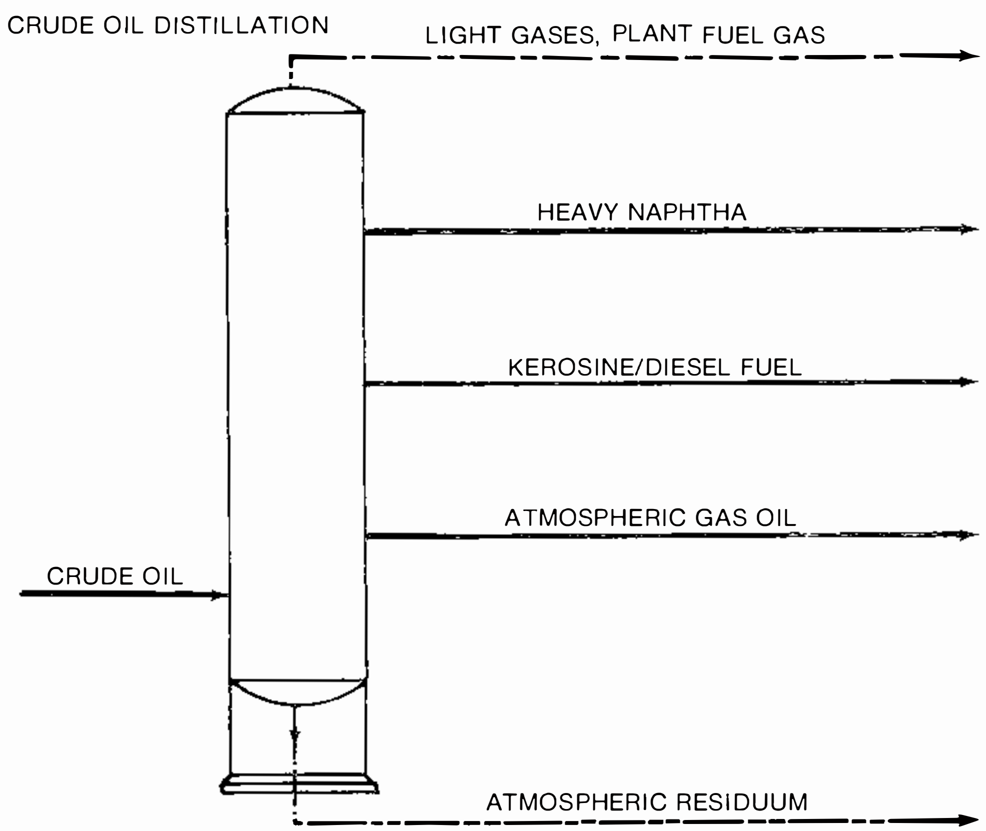


Figure 27. Crude Oil Skimming or Topping Plant.

The following legend applies to Figures 27 through 54:

HYDROCARBON

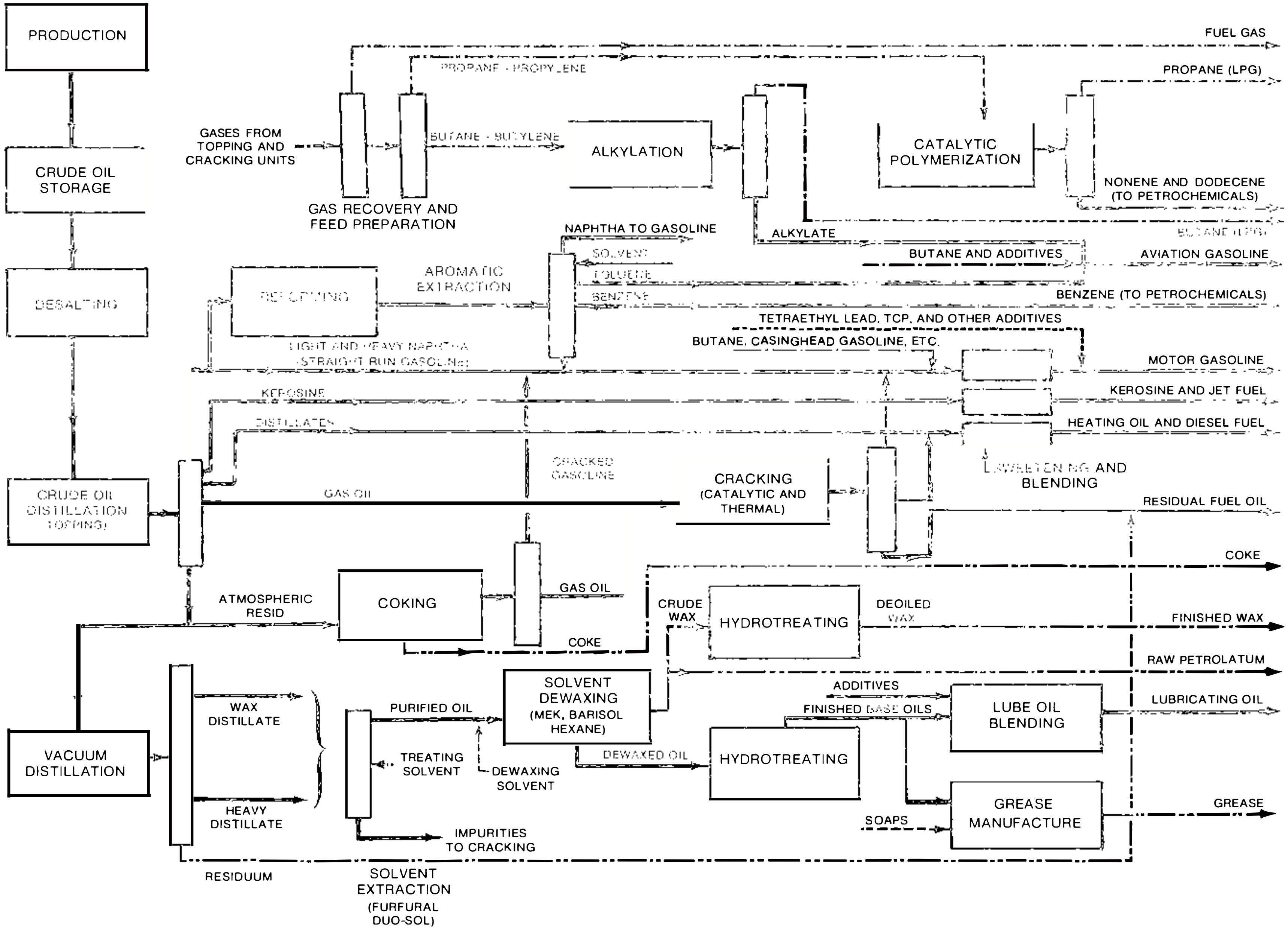
WATER

GASES

SOLIDS, SEMI-SOLIDS

ADDITIVES, CHEMICALS

NO DESIGNATION



NOTE: The legend appears on Figure 27.

Figure 28. Simplified Flow Chart of a Complex Refinery.

However, a refinery is designed based on the available crude oil and the market demand for products.

The operation of a refinery can be divided into seven steps:

- Separation of Crude Oil. The most widely used methods for separating crude oil are atmospheric and vacuum distillation. Solvent extraction, absorption, and crystallization are also used, but to a much smaller degree.

- Conversion of Hydrocarbon Molecules. Conversion processes, which change the size or structure of the hydrocarbon molecule, convert some of the crude oil fractions into higher value products. The most common conversion processes are cracking (thermal, catalytic, viscosity breaking, hydrocracking, and coking), combining (alkylation and polymerization), and rearranging (catalytic reforming and isomerization).

- Treating Crude Oil Fractions. Some of the original sulfur compounds are converted to hydrogen sulfide (H_2S), which can be separated and converted to elemental sulfur. Undesirable sulfur compounds are removed by treating processes such as hydrodesulfurizing and chemical treating.

- Blending Hydrocarbon Products. Most petroleum products are a blend of hydrocarbon fractions or components produced by various refinery processes. Motor gasoline is a blend of various gasoline blending stocks, including reformate, alkylate, straight-run naphtha, thermally and catalytically cracked gasoline, and necessary additives. The vast number of fuel oils, lubricants, and asphalt products are blends of refinery base stocks.

- Auxiliary Operating Facilities. A number of refinery units are used to maintain normal operating conditions. These units support processes such as hydrotreating, improve efficiency by allowing re-use of water and the use of sour gas as fuel, and help the refinery meet environmental standards. Included among the functions of auxiliary operating facilities are hydrogen production, light ends recovery, acid gas treating, sour water stripping, sulfur recovery, tail gas treating, and wastewater treatment.

- Refinery Offsite Facilities. Refinery offsite facilities are equipment and systems used to support refinery operations. These facilities include storage tanks, steam generating systems, flare and blowdown systems, cooling water systems, receiving and distribution systems, and refinery fire control systems. In addition, garages, maintenance shops, storehouses, laboratories, and necessary office buildings are considered offsite facilities.

- Emission and Effluent Control. Refineries generate air emissions, wastewater, solid waste, and noise, which must be

controlled for efficient processing and environmental protection. The control of pollutants that can damage the environment is an important part of refinery operations. Refinery environmental controls are discussed in detail later in this chapter.

SEPARATION OF CRUDE OIL

Following salt and water removal (desalting), crude oil is separated into the desired boiling range fractions by atmospheric and vacuum distillation.

I. Desalter

The desalter is normally the starting point of the separation process. As shown in Figure 29, the crude oil is pumped from tankage, preheated by heat exchange with various product streams (fractions), and sent to the desalter. Desalting removes inorganic salts from crude oil so that these salts will not contribute to the fouling and corrosion of process equipment. The process also removes the soluble trace metals present in the water phase, which can poison downstream process catalysts. Chemicals and water are added to the crude oil, and oil/water separation occurs by gravity in the presence of a high voltage electrostatic field. This helps agglomerate the water droplets, which contain the salts, and separates the water from the oil. The oil is removed from the top of the desalter vessel, and the water from the bottom. The water is then sent to the wastewater treatment plant.

II. Atmospheric Distillation Unit

Crude oil from the desalter is pumped to a furnace where the oil is further heated and fed to the atmospheric distillation unit. All petroleum distillation processes are fundamentally the same and require the following equipment: heat exchangers; furnaces or other heaters; a fractionating tower or column; condensers and coolers; pumps and connecting lines; storage and accumulator tanks; and instrumentation. In adapting these units of equipment, many factors must be considered. Among the most important are:

- Boiling range of the stocks
- Heat stability of the stocks
- Product specifications.

As shown in Figure 29, the atmospheric distillation tower separates the crude oil into fractions having specific boiling point ranges. The fractions with the lowest boiling range are recovered as overhead streams and are either fuel gas, light naphtha, or straight-run gasoline. These fractions are used as reformer feedstocks, gasoline blending stocks, petrochemical feedstocks, solvents, and liquefied petroleum gases (LPG). The intermediate

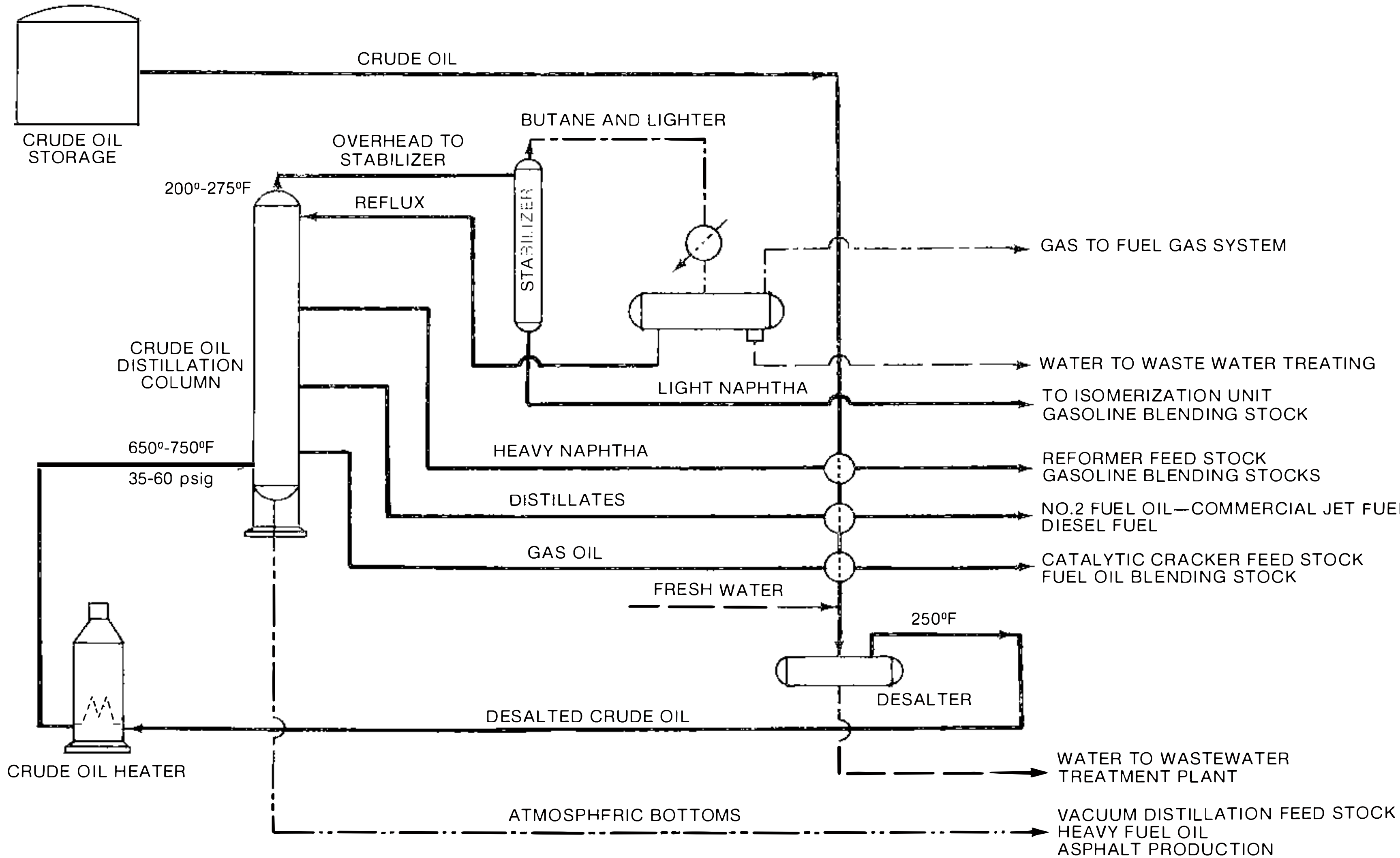


Figure 29. Crude Oil Distillation Unit.

NOTE: The legend appears on Figure 27.

boiling range fractions are gas oil, heavy naphtha, and distillates. These fractions are used to produce kerosine, diesel fuel, fuel oil, jet fuel, blending stocks, and catalytic cracker feedstocks. The high boiling point stream, or atmospheric bottoms, is used to produce asphalt or No. 6 fuel oil, or as feed to a vacuum distillation unit for the production of lubricants.

III. Vacuum Distillation Unit

The charge stock for the vacuum distillation unit (Figure 30) consists of heated atmospheric bottoms from the crude oil distillation unit (Figure 29). The vacuum can be produced by using steam eductors or vacuum pumps. The equipment commonly used are two-stage steam-jet eductors and surface condensors. At the reduced pressure, the oil vaporizes at a lower temperature, allowing the distillation to occur with a minimum of high-temperature cracking.

The product streams from the vacuum tower include light vacuum gas oil, heavy vacuum gas oil, and vacuum tower bottoms or residuum. These streams can be further processed depending upon the desired products. The vacuum gas oil may be sent to the catalytic cracker to produce gasoline blending stocks or it may be recovered for heating fuel. The vacuum bottoms may be used as fuel oil, used for the production of asphalt and lubricants, or sent to a coker for conversion to gasoline components, coke, and gas. If low-sulfur fuel oil is required, the vacuum bottoms may have to be desulfurized prior to blending.

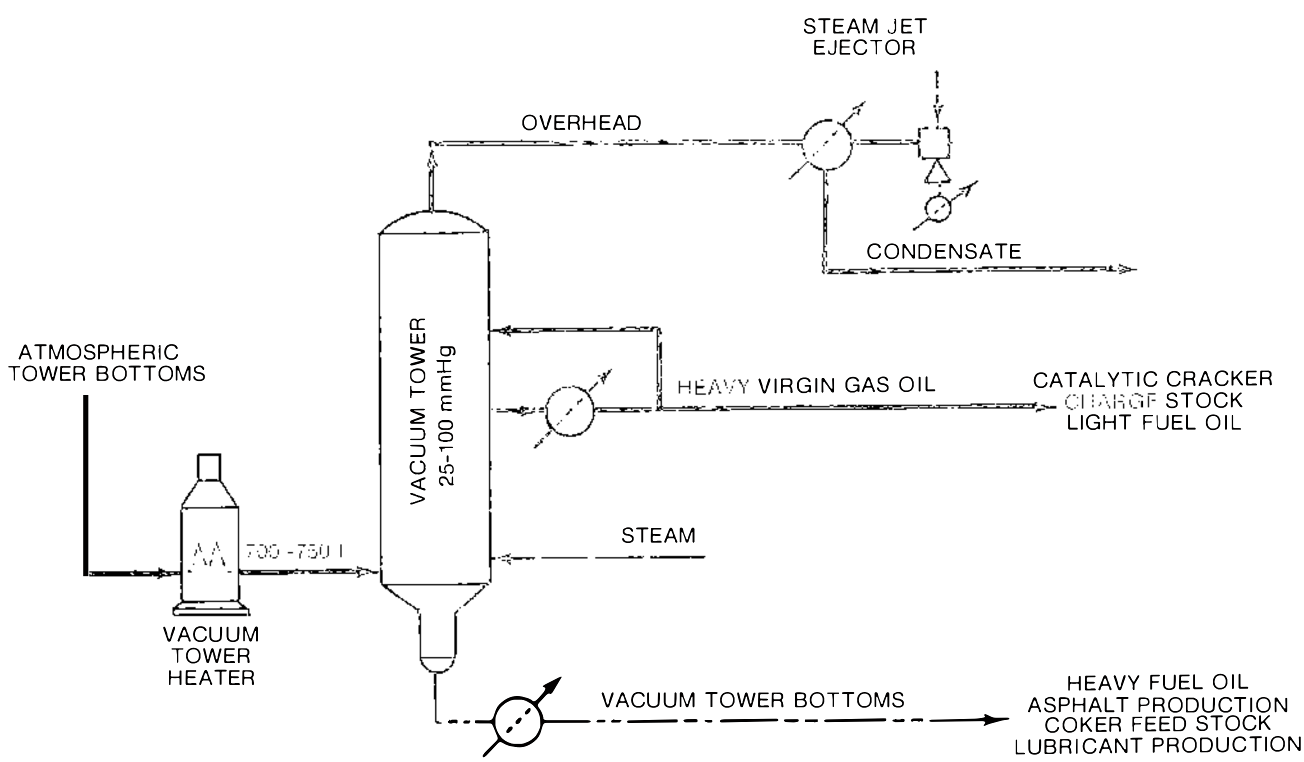


Figure 30. Vacuum Distillation Unit.

NOTE: The legend appears on Figure 27.

CONVERSION OF HYDROCARBON MOLECULES

Conversion processes change the size or structure of the hydrocarbon molecules, converting them into higher value products. The more common conversion processes are:

- Cracking processes (thermal cracking, coking, viscosity breaking, catalytic cracking, and hydrocracking)
- Combining processes (alkylation and polymerization)
- Rearranging processes (catalytic reforming and isomerization).

I. Cracking Processes

Cracking processes break large hydrocarbon molecules into smaller, lower-boiling-point molecules. During the process, some of the molecules combine (polymerize) to form larger molecules. The usual products of cracking are gaseous hydrocarbons, gasoline blending stocks, gas oil, fuel oil, and coke. Sour water generated during the process is sent to the sour water stripping unit. The off-gases from the fractionating column are treated by amine scrubbing, which removes the H_2S. The H_2S then is sent to the sulfur recovery unit.

A. Thermal Cracking

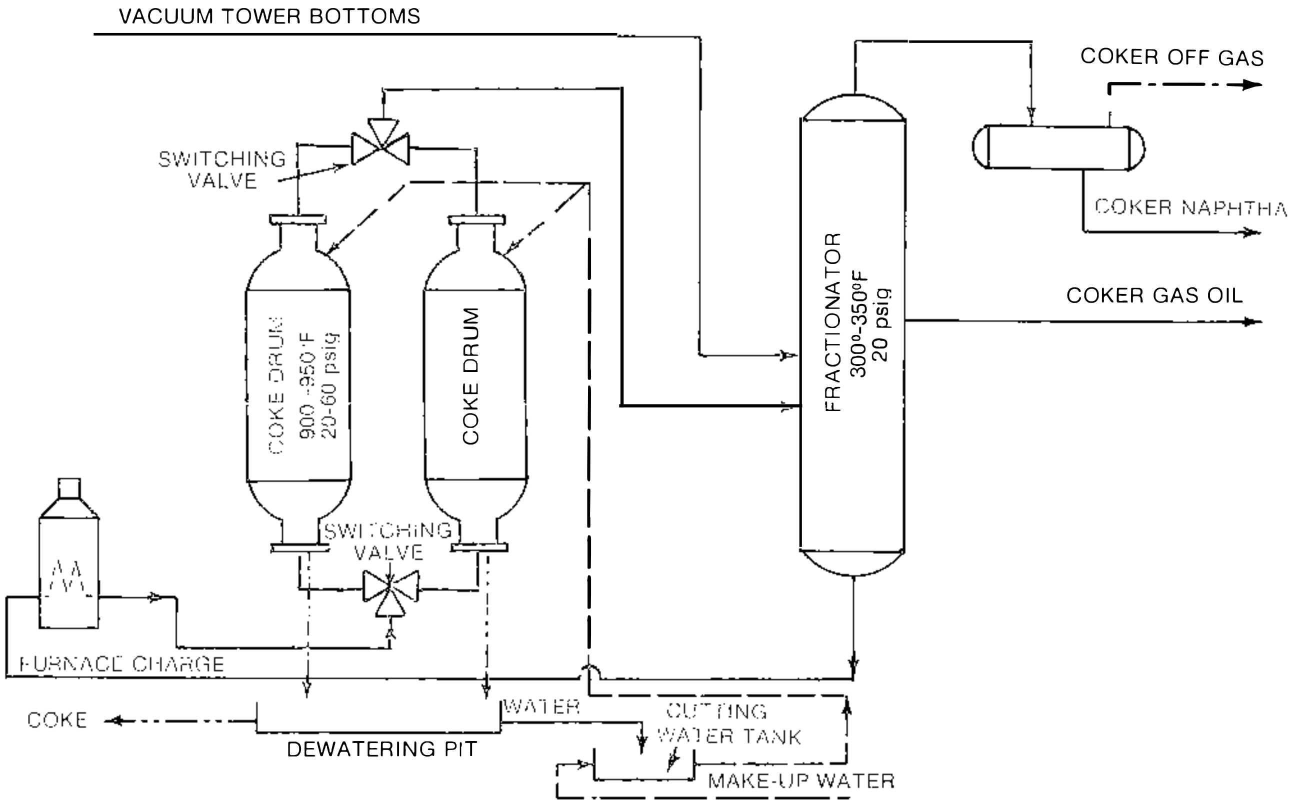
In the past, cracking was accomplished solely by application of heat and was known as thermal cracking. The thermal cracking process was developed around 1871 and was widely practiced during the 1920-1950 period. Today, thermal cracking is used mostly in only two of its more extreme forms, coking and viscosity breaking.

1. Coking

There are two coking processes that are employed extensively -- delayed and fluid coking. Coking is accomplished at a high temperature and low pressure. It is a valuable process for upgrading heavy charge stock such as resids and very heavy crude oils. In the coking unit, atmospheric bottoms or vacuum residuum are cracked to produce fuel gas, gasoline blending stocks, distillates, and petroleum coke. A delayed coking unit is shown in Figure 31.

The coker charge is fed directly to the fractionator where the feed combines with the heavy recycle oil from the coke drums. The combined feed is pumped to the coker furnace where it is heated. This heating produces partial vaporization and mild cracking. The liquid/vapor mixture then enters the coke drum where the liquid undergoes further cracking until it is converted to hydrocarbon vapors and coke.

The coking unit typically has one or more pairs of coke drums. In normal operation one drum is in service while the other is being decoked. Decoking involves cooling the coke, and then cutting it



NOTE: The legend appears on Figure 27.

Figure 31. Delayed Coking Unit.

from the drum with a high-pressure water drill. The coke and water drop from the drum into a pit where the coke dewaters, and the cutting water is recovered for re-use. The coke is loaded into transport vehicles or is stored offsite.

Fluid coking is a similar thermal cracking process, producing similar products, but coking occurs in a fluid bed. This is a continuous process, unlike delayed coking.

In 1976, a new process, termed "flexicoking," was first used in Japan by the Toa Oil Company. The process is an adjunct to fluid coking and converts heavy, high-sulfur vacuum bottoms into petroleum products and fuel gas. Only a small quantity of ash or coke residue is produced.

2. Viscosity Breaking

Viscosity breaking, or visbreaking, is a mild form of thermal cracking that is used primarily to improve the quality of the fuel oil. The decomposition process is usually conducted at low cracking temperatures (860°F to 900°F). This process produces small amounts of gasoline blending stocks, gas oil, and fuel oils.

B. Catalytic Cracking

Catalytic cracking uses a catalyst in combination with high temperatures to convert atmospheric and vacuum gas oils and stocks

derived from other refinery operations into fuel gases, light gases, and gasoline and distillate fuel components. This process normally takes place in the fluid catalytic cracking unit (FCCU). Olefin-rich light gases are normally directed to alkylation or polymerization operations to produce high-octane gasoline blending stocks. Typically, yields of gasoline boiling range products will exceed 50 to 65 volume percent of the FCCU feed.

A typical FCCU is shown in Figure 32. While there are numerous FCCU designs currently in use, they employ similar operating principles. The catalyst used in the process must be regenerated to remove coke that forms on its surface during the reaction. This is done in a separate regenerating vessel by passing air through the catalyst. The catalyst regeneration produces carbon monoxide (CO), sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulates. Recent improvements in technology have minimized the formation of CO.

C. Hydrocracking

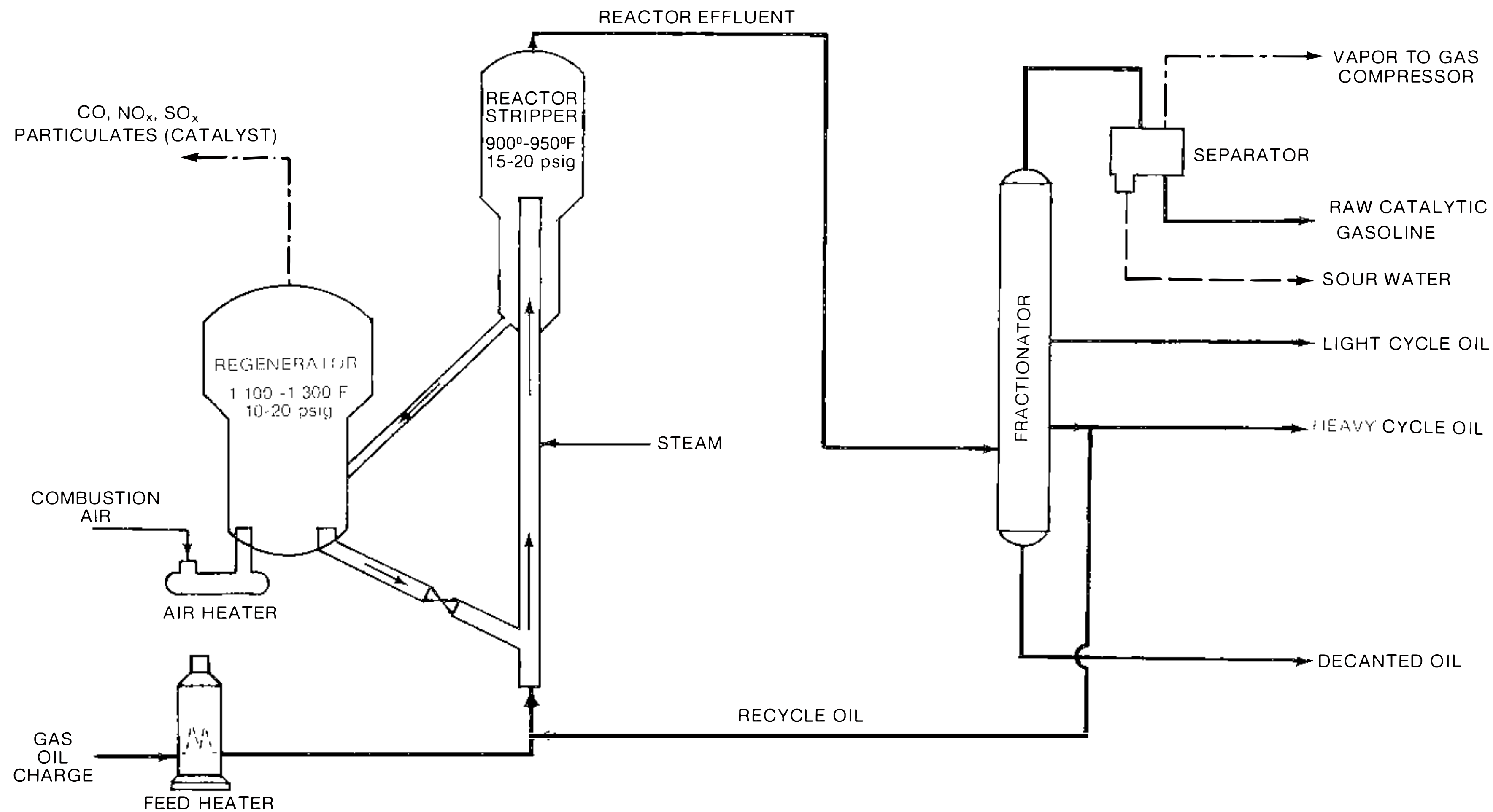
Hydrocracking differs from catalytic cracking in four distinct ways: hydrogen is utilized in the process; operating pressures are substantially higher; temperatures are somewhat lower; and a different type of catalyst is employed. The process has an advantage over catalytic cracking in that high-sulfur feedstocks can be processed without prior desulfurization. The yield of specific products will depend upon how the hydrocracking unit is operated. For example, yields of jet fuel plus diesel fuel equal to approximately 85 to 90 volume percent of feed can be achieved, with concurrent production of LPG and gasoline. The process produces high-quality gasoline and distillates and accepts a wide variety of feedstocks, including naphthas, gas oils, and heavy aromatic feedstocks. Hydrogen used for this process is generated by a hydrogen plant or is a by-product from the catalytic reformer. A typical two-stage hydrocracker is shown in Figure 33.

II. Combining Processes

Combining processes join together small hydrogen-deficient molecules (olefins) that are recovered from thermal and catalytic cracking to produce more valuable gasoline blending stocks. Two processes, alkylation and polymerization, are normally utilized for combining the olefins with isobutane.

A. Alkylation

The alkylation process combines light olefins, primarily a mixture of propylene and butylenes, with isobutane to produce a blending stock that is one of the highest quality components of motor gasoline. The final product, called alkylate, has excellent antiknock properties. It is clean burning, has high Research and Motor method octane number ratings, and has excellent performance ratings. The union of the olefins and isobutane takes place in the presence of a catalyst, either hydrofluoric or sulfuric acid, under conditions selected to maximize product yield and quality.



NOTE: The legend appears on Figure 27.

Figure 32. Fluid Catalytic Cracking Unit.

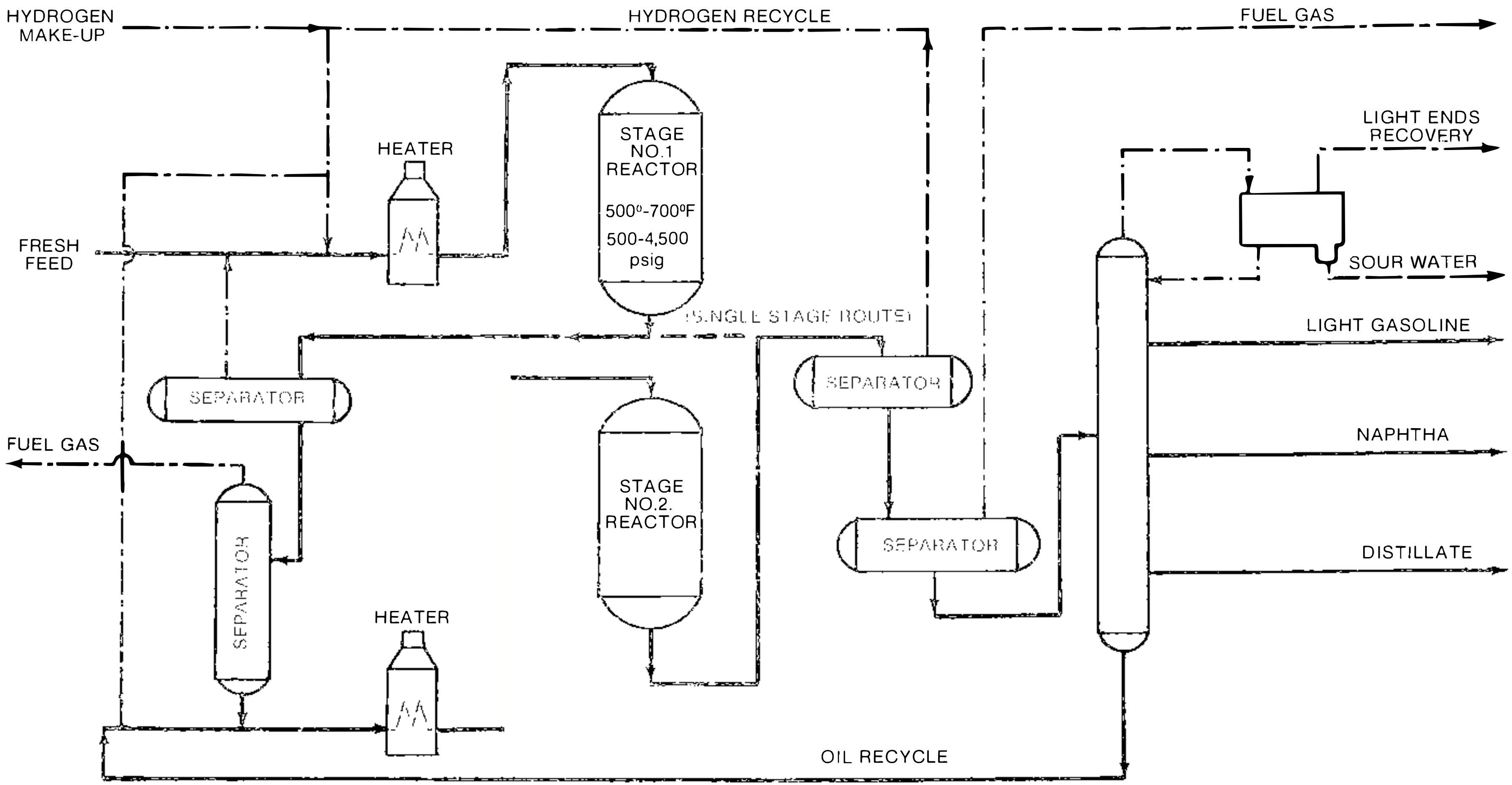


Figure 33. Typical Two-Stage Hydrocracker Unit.

NOTE: The legend appears on Figure 27.

The process utilizing hydrofluoric acid as the catalyst is shown in Figure 34. The unit feed, consisting of C_3 and C_4 olefins and isobutane, is mixed with recycled acid and fed to the reactor-settler where the alkylation reaction takes place. The combined products are sent to a fractionator where the alkylate product is separated from the unreacted feed, catalysts that carry over, and propane and butane that was formed by the reaction. The product or alkylate may first be debutanized before being sent to storage for gasoline blending.

Construction materials for hydrofluoric acid alkylation units include plain carbon steel; some of the rundown lines, however, are constructed of Monel alloy. All unit lines are jacketed and connected to a "blowdown" or water spray pump so that gaseous acid will be caught if a break occurs. Much of the operation is by remote control; when the operator must approach the unit, face masks and rubberized clothing are worn.

The hydrofluoric acid alkylation unit includes a hydrofluoric acid regenerator, which continuously purifies a small side stream of the acid. The tar-like substance that is formed in the regenerator may be disposed of by incineration or neutralized with lime and handled as a solid waste. Also, the spent caustic from the unit is handled as solid waste.

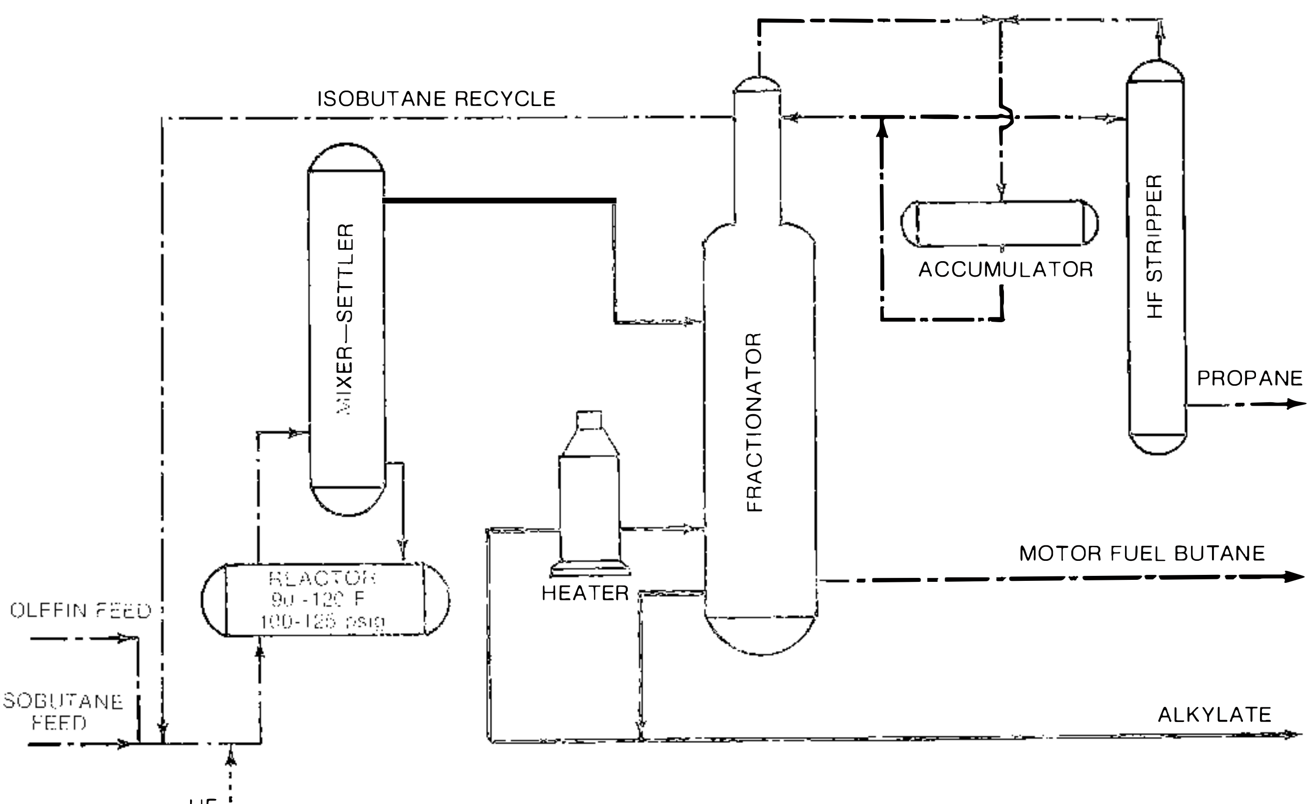


Figure 34. Hydrofluoric Acid Alkylation Unit.

NOTE: The legend appears on Figure 27.

B. Polymerization

Polymerization combines light olefins from thermal and fluid catalytic cracking units to form hydrocarbons of higher molecular weight. Two molecules of isobutylene (C_4H_8) may be combined to form one molecule of di-isobutylene (C_8H_{16}). This product, formed by the union of two olefin molecules, is referred to as a dimer. That formed by three such molecules is known as a trimer. Two unlike olefins may also be combined, resulting in a product known as a copolymer. By-product gases are used to produce a wide variety of products ranging from gasoline blending stocks to solids that can be used as plasticizers. Polymerization of a mixture of propylene and butylene to produce a blending stock for gasoline is the most common polymerization operation. The most commonly used process employs phosphoric acid as a catalyst.

III. Rearranging Processes

Rearranging processes are those in which the molecule is changed to produce a product of different characteristics. The two most widely used rearranging processes are catalytic reforming and isomerization.

A. Catalytic Reforming

Catalytic reforming is a process used to upgrade low-octane naphthas to produce high-octane blending stocks or high yields of aromatic hydrocarbons for petrochemical feedstocks (i.e., benzene). The final product will depend on reactor temperature and pressure, the catalyst used, and the hydrogen recycle rate. Reforming catalysts contain platinum and are readily deactivated (poisoned) by sulfur and nitrogen, so the feedstock must be pretreated prior to being charged to the reforming unit.

Catalytic reforming is the octane number generator for most gasoline-oriented refineries. The gasoline blending stocks from other operations such as FCCU, alkylation, hydrocracking, and polymerization, are of relatively fixed octane number quality. The catalytic reforming process is capable of efficiently yielding gasoline blending stocks within an octane number range from the low 80's to over 100 Research clear (unleaded). As operation severity is increased to raise the octane number, gasoline yield decreases. On the basis of the gasoline produced per unit of feedstock, typical yields can range from 70 to over 90 volume percent for high- to low-octane-number operations. This process also generates hydrogen that is required for many of the operations employed in modern refineries.

A typical catalytic reforming unit is shown in Figure 35. The naphtha feedstock is mixed with recycle hydrogen-rich gas, heated in a furnace, and fed to the first reactor. Because the reforming reaction requires heat (endothermic), the product must be reheated before entering the next reactor. This process typically is repeated in three subsequent reactors. The liquid product passes to

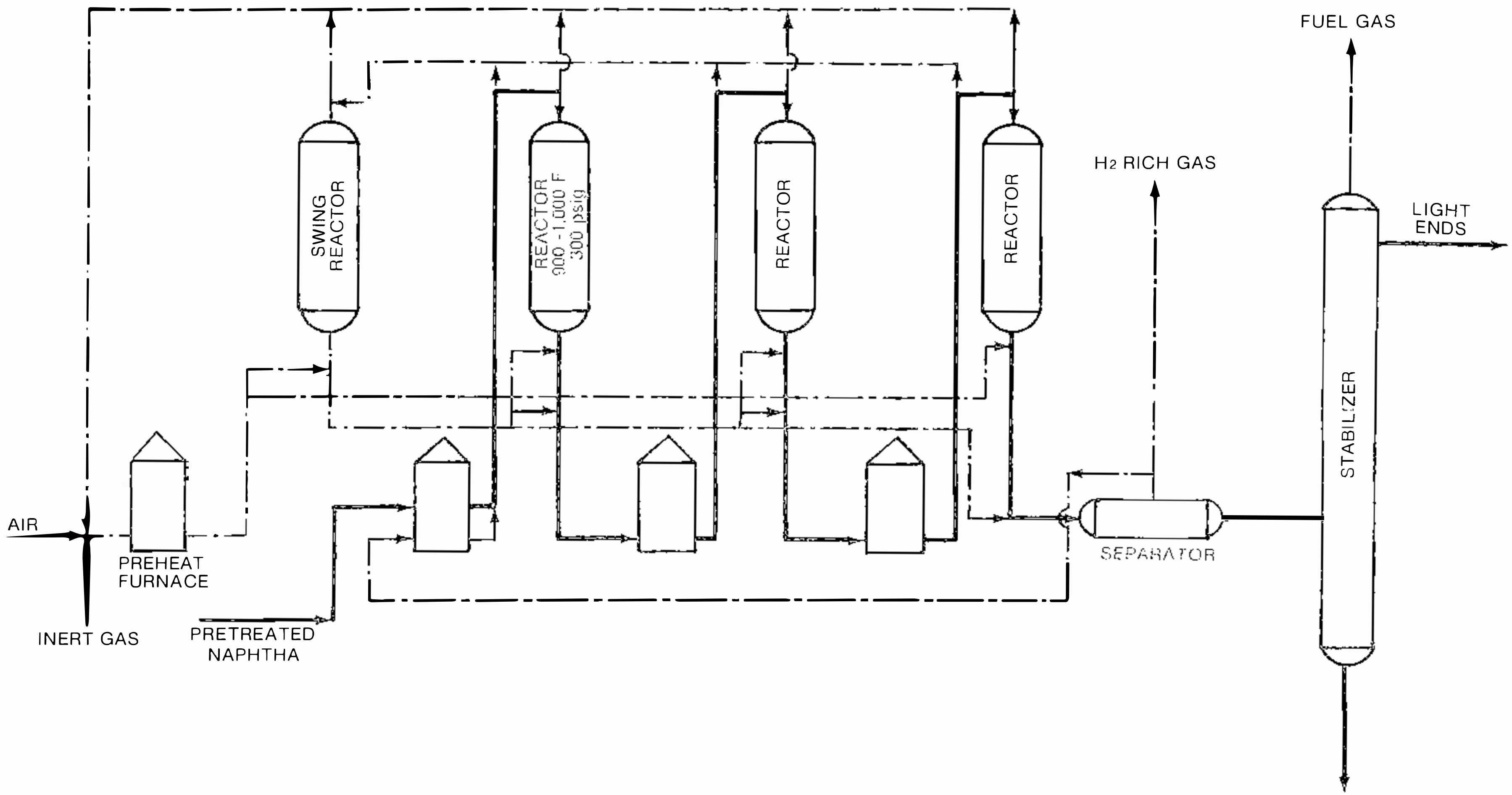


Figure 35. Catalytic Reforming Unit.

NOTE: The legend appears on Figure 27.

a separator to remove the hydrogen-rich gas and then to a stabilizer for final separation of light gases and product. The reformate product then goes to storage for blending into gasoline. The light gases, consisting of mostly propane and butane, are sent to the light ends recovery unit.

The catalyst requires regeneration, which may be accomplished by utilizing a swing reactor, as shown in Figure 35. As in hydrotreating and FCCU, coke deposited on the catalyst surface is burned off under controlled conditions.

B. Isomerization

Isomerization units are employed to convert n-butane, n-pentane, and n-hexane (low-octane, straight chain hydrocarbons) to high-octane, branched chain isomers.

Figure 36 shows a typical light naphtha isomerization process. In this process, desulfurized pentane/hexane (C_5/C_6) mixtures are fed to the de-isopentanizers to remove the isopentane present in the feed. The n-pentane and n-hexane mixture is dried, mixed with organic chloride catalyst promoter and hydrogen, and fed to the reactor. The product is cooled and fed to a separator where excess hydrogen is removed to be recycled. The product is then fed to a stabilizer to remove low-boiling light hydrocarbons. The stabilizer bottom products are used for gasoline blending stocks or may be further fractionated to remove unreacted n-pentane, n-butane, and n-hexane for recycling.

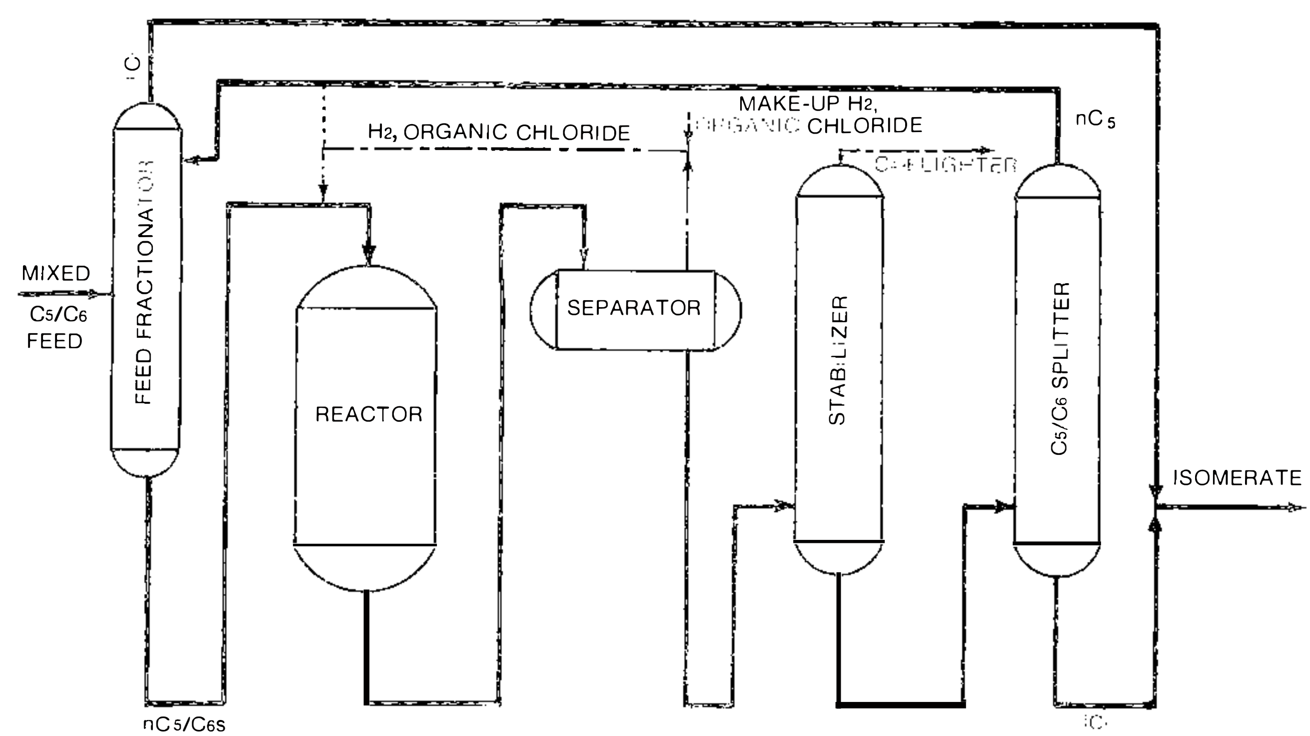


Figure 36. Pentane/Hexane (C_5/C_6) Isomerization Unit.

NOTE: The legend appears on Figure 27.

TREATING CRUDE OIL FRACTIONS

With continuing emphasis on producing greater yields of higher octane gasoline and low-sulfur fuel oil, it is necessary to upgrade materials that are used directly as gasoline components or blended into fuel oil. Components such as thermal naphthas derived from thermal cracking, visbreaking, and coking operations, as well as high-sulfur naphthas and distillates from crude oil distillation containing sulfur and nitrogen, require treating.

I. Hydrodesulfurization

Hydrodesulfurization is a catalytic process used to remove sulfur, nitrogen, olefins, arsenic, and lead from liquid petroleum fractions. Typically, hydrodesulfurization units are employed before such processes as catalytic reforming because the process catalysts used in reforming become inactive if the feedstock contains these impurities. Hydrodesulfurization may be used prior to catalytic cracking to reduce the sulfur emissions from the regenerator and improve product yields. It may also be used to upgrade petroleum fractions into finished products such as kerosine, diesel fuel, and fuel oils.

Hydrodesulfurization processes are used on a wide range of feedstocks from naphtha to heavy residual oils. In general, the hydrodesulfurizing of process streams from sour crude oil requires greater quantities of hydrogen than does hydrodesulfurizing of sweet crude oil fractions.

In a typical hydrodesulfurizing process (Figure 37), the feed is mixed with make-up hydrogen from the reformer or hydrogen

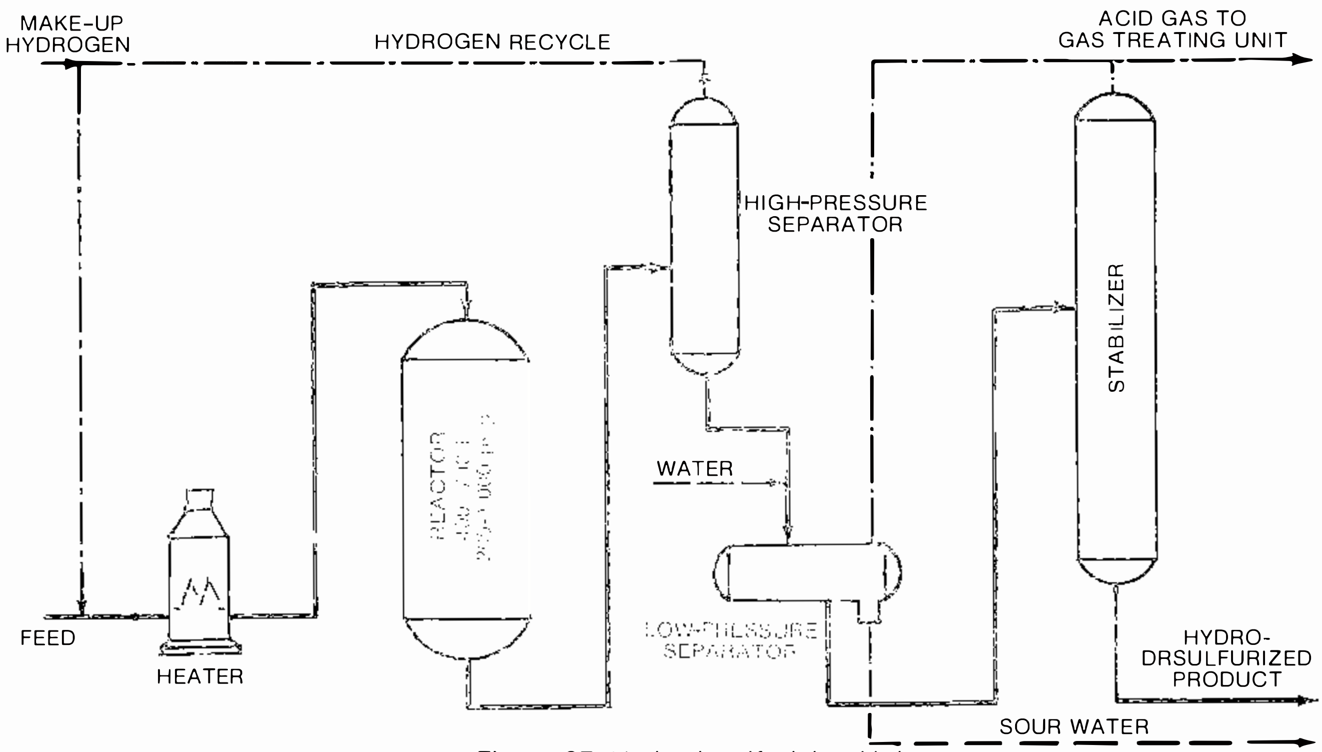


Figure 37. Hydrodesulfurizing Unit.

NOTE: The legend appears on Figure 2 .

manufacturing plant. The mixture is heated and fed to the catalyst reactor, where sulfur and nitrogen are converted into H_2S and ammonia (NH_3).

Product from the reactor goes to the high-pressure separator, where excess hydrogen is flashed off and returned to the reactor. The product then passes to the low-pressure separator where H_2S, NH_3, noncondensable hydrocarbon gases, and hydrogen are removed. The gases from the low-pressure separator are sent to the gas treating system to remove H_2S. The liquid product is then sent to the stabilizer where the remaining light material is stripped and is sent to the fuel gas treating system. The sour water generated during the process is sent to the sour water stripping unit.

II. Chemical Treating

The use of chemical treating to directly remove sulfur from petroleum fractions has declined as hydrodesulfurization has increased. Chemical treating processes are used, however, to remove such impurities as carbon dioxide (CO_2), oxidants, and various corrosive compounds from processing systems.

A variety of gasoline sweetening (mercaptan removal) processes are available. The most widely used process employs sodium hydroxide with added catalysts or promoters (Figure 38). The process

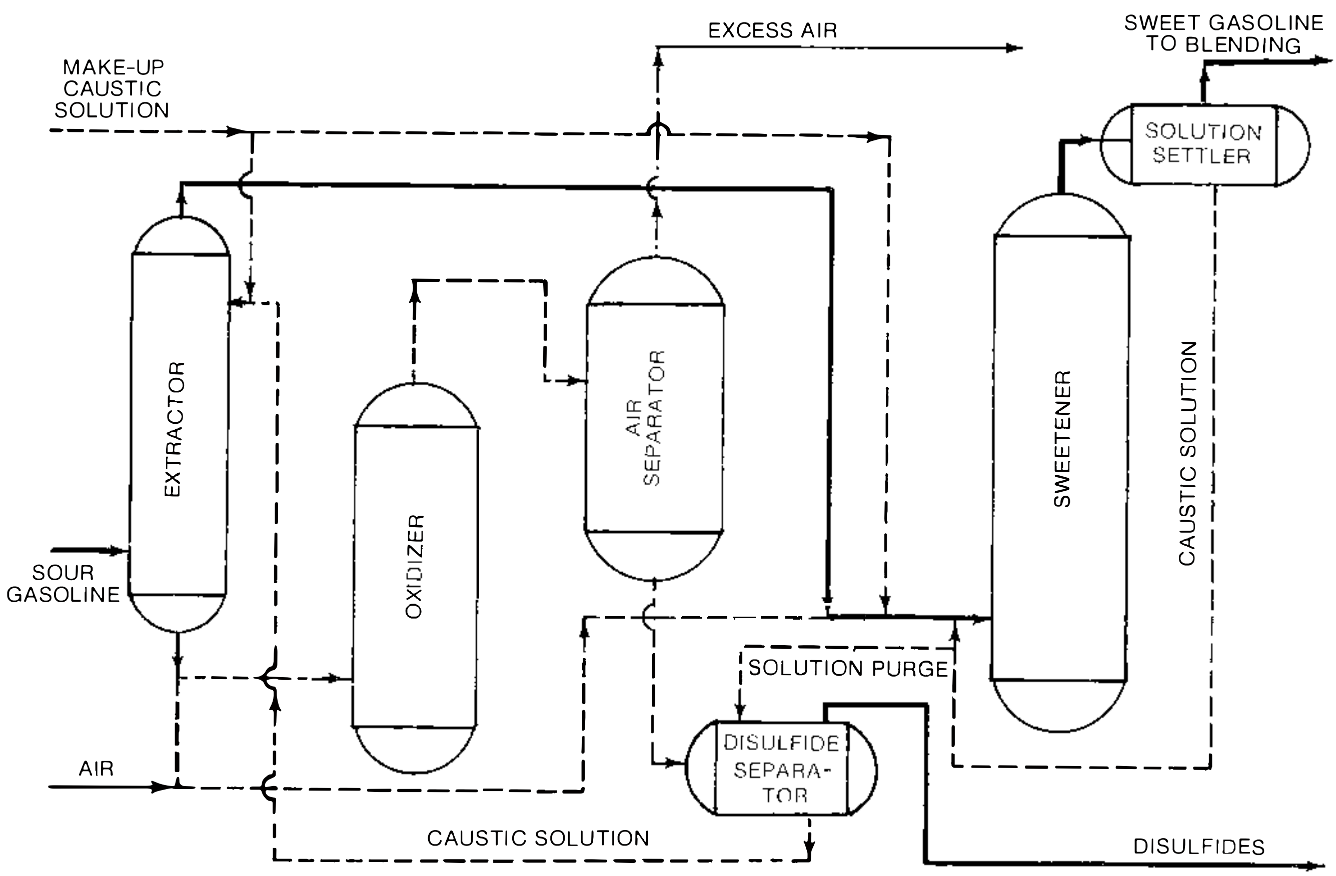


Figure 38. Gasoline Sweetening Unit.

NOTE: The legend appears on Figure 27.

converts the mercaptans to less objectional disulfides. The use of sweetening is primarily dependent upon the sulfur and/or mercaptan content of the crude oil, the sulfur specification of the gasoline, and whether the original feedstock had been hydrodesulfurized prior to catalytic cracking.

BLENDING HYDROCARBON PRODUCTS

The last major step in the refinery operation is the blending of various fractions into finished products. All grades of motor gasoline are blends of various fractions, including reformate, alkylate, straight-run gasoline, thermally and catalytically cracked gasoline, coker gasoline, butane, and necessary additives. Furnace oil and diesel fuels may be blends of virgin distillates and cycle oil. Jet fuels may be straight run virgin distillates or include naphtha in the blend. The vast number of lubricating oils are blends of a relatively small number of refined based stocks plus additives to impart specific properties to most crankcase and specialty lubricants. In some cases these additives may total more than 15 to 20 percent of the finished lubricant. Asphalt is blended from select residual base stocks according to the application desired.

For example, in gasoline blending, the components or blending stocks from the process unit, such as butane, alkylate, isomerization stock, reformate, catalytic gasoline, naphtha or straight-run gasoline, coker gasoline, and additives, are blended to meet gasoline specifications. The mixing of the components is normally accomplished by automated in-line blending (Figure 39). Gasoline blending components are fed into a system of proportional metering pumps and control valves to the gasoline header. The metering pumps ensure that each component is fed in the proper proportion. The components are mixed by the flow turbulence in the header and sent to a series of on-stream analyzers, which continually monitor the product for octane number and vapor pressure. The monitors automatically control the metering system to ensure proper portions of each component.

AUXILIARY OPERATING FACILITIES

Auxiliary operating facilities are necessary to support process units requiring hydrogen, collect and treat gases for refinery fuels, control air emissions, meet water effluent standards, and re-use water.

I. Hydrogen Production Unit

Hydrogen is required for a number of refining units, including hydrodesulfurization, hydrocracking, and isomerization. The primary source of hydrogen is the catalytic reforming process. Additional hydrogen may be produced by the steam reforming of available hydrocarbons such as methane, refinery fuel gases, propane, butane, or desulfurized light naphtha, or by the partial oxidation of heavier hydrocarbons.

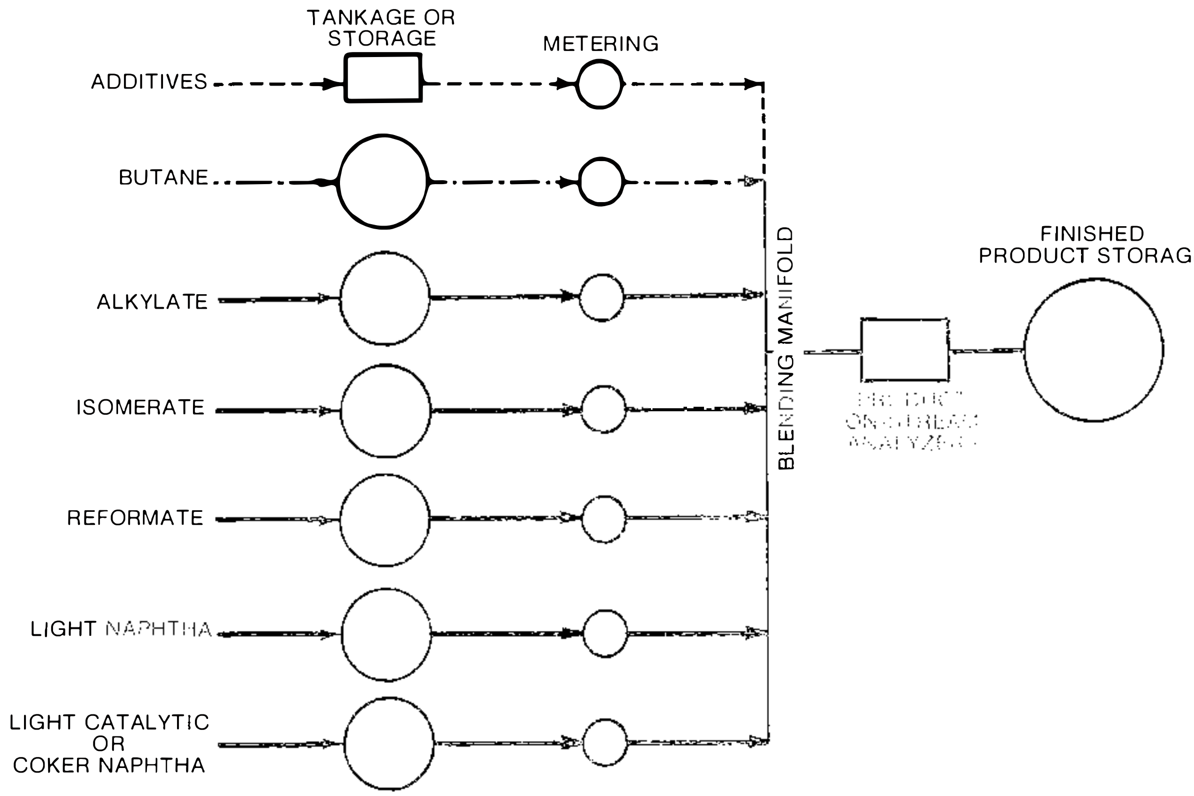


Figure 39. Gasoline In-Line Blending System.

NOTE: The legend appears on Figure 27.

The flow diagram for manufacturing hydrogen by the steam reforming process is shown in Figure 40. The feed to the unit normally contains traces of sulfur, which are removed by absorption or activated carbon. The removal of the sulfur is necessary to avoid poisoning the process catalyst. The process employs two beds of activated carbon; while one bed is in use the other is being regenerated. Upon completion of the regeneration, the sequence is reversed. Regeneration is accomplished by heating the carbon with steam to remove absorbed sulfur. The used steam is condensed and sent to the sour water stripper.

Desulfurized naphtha and natural gas are mixed with steam passed through catalyst-filled tubes in the reformers. The reformer gas containing hydrogen, CO, CO_2, and excess steam is passed through a shift converter where CO and steam are converted to hydrogen and CO_2. The CO_2-rich gas is scrubbed to remove practically all the CO_2, yielding 95-98 percent pure hydrogen.

In the manufacture of hydrogen by the partial oxidation process, the feed to the units is typically bottom products from the vacuum tower or heavy coker gas oil. This process avoids the necessity of using naphtha or other, more valuable hydrocarbons as hydrogen plant feedstock.

In the partial oxidation process, the residual oil is fed to a combustion chamber where it is partially burned in the presence of steam and oxygen. Gases leaving the combustion chamber are

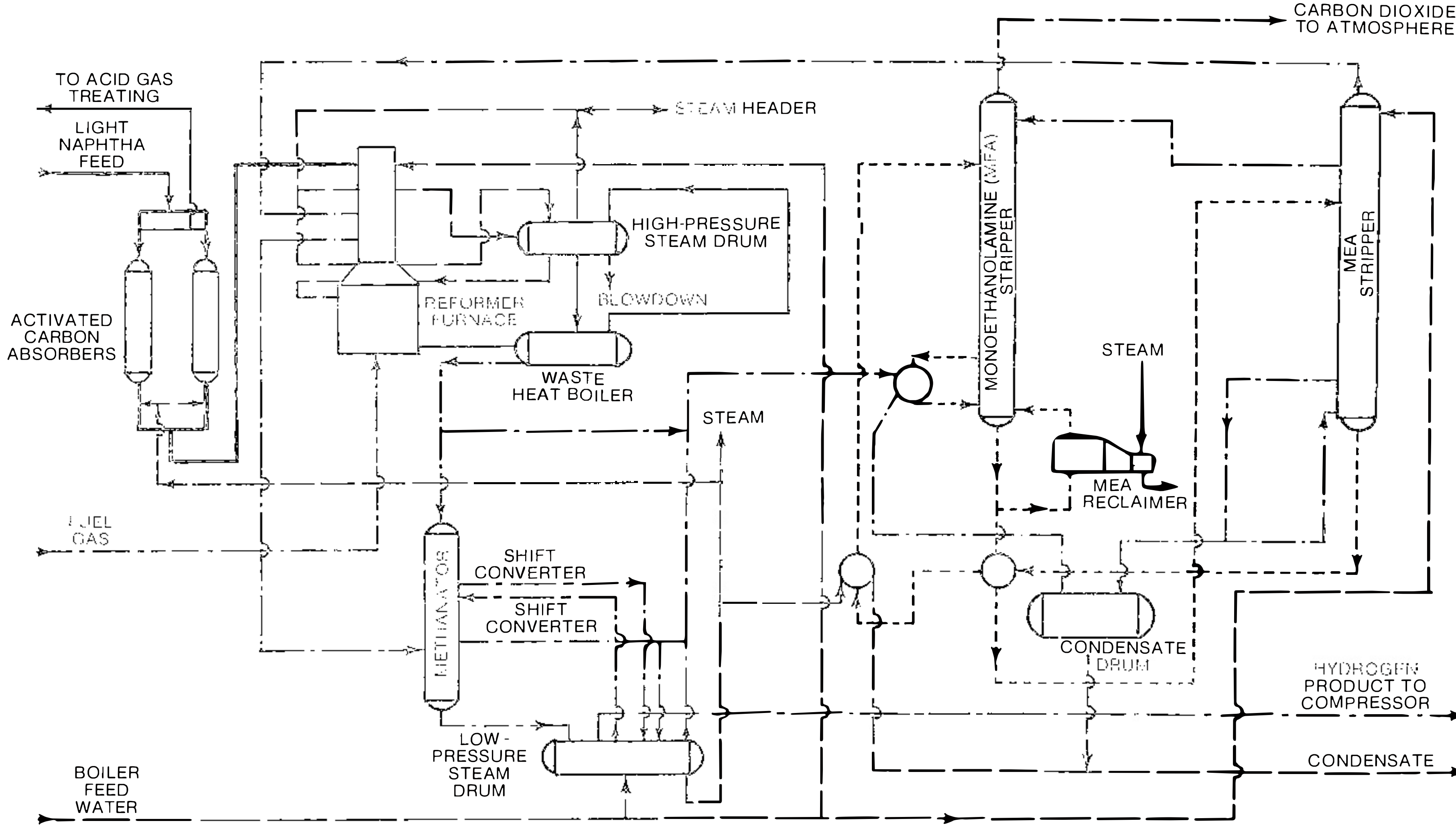


Figure 40. Hydrogen Production Unit.

NOTE: The legend appears on Figure 27.

composed primarily of hydrogen and CO and have a temperature of 2,000°F to 2,800°F. The gases are then quenched with water and steam and fed to a shift converter for further conversion of the CO and steam to hydrogen. The gases are then purified by absorption and the hydrogen product is sent to storage or process units.

II. Light Ends Recovery Unit

The term "light ends" refers to light hydrocarbon gases having four or fewer carbon atoms in the molecule. These include methane, ethane, propane, and butane. Included in this group are C_3 and C_4 olefins and isobutane. The purpose of this unit is to separate these gases for further use in product production or refining.

The flow diagram for the unit is shown in Figure 41. The feed to this unit is desulfurized gases that have been collected from the various process units. The gases are first liquefied by compression and cooling, then sent to a surge drum to remove condensed moisture. The mixture is pumped to the de-ethanizer where methane and ethane are separated from the mixture and recovered for refinery fuel. The de-ethanized bottoms are sent to the de-propanizer where propane and butanes are separated. These streams may be further processed to separate the olefins and isobutane from the propane and normal butane. The olefins and isobutane are used for alkylation unit feedstock. The propane is recovered for LPG and normal butane is sent to gasoline blending.

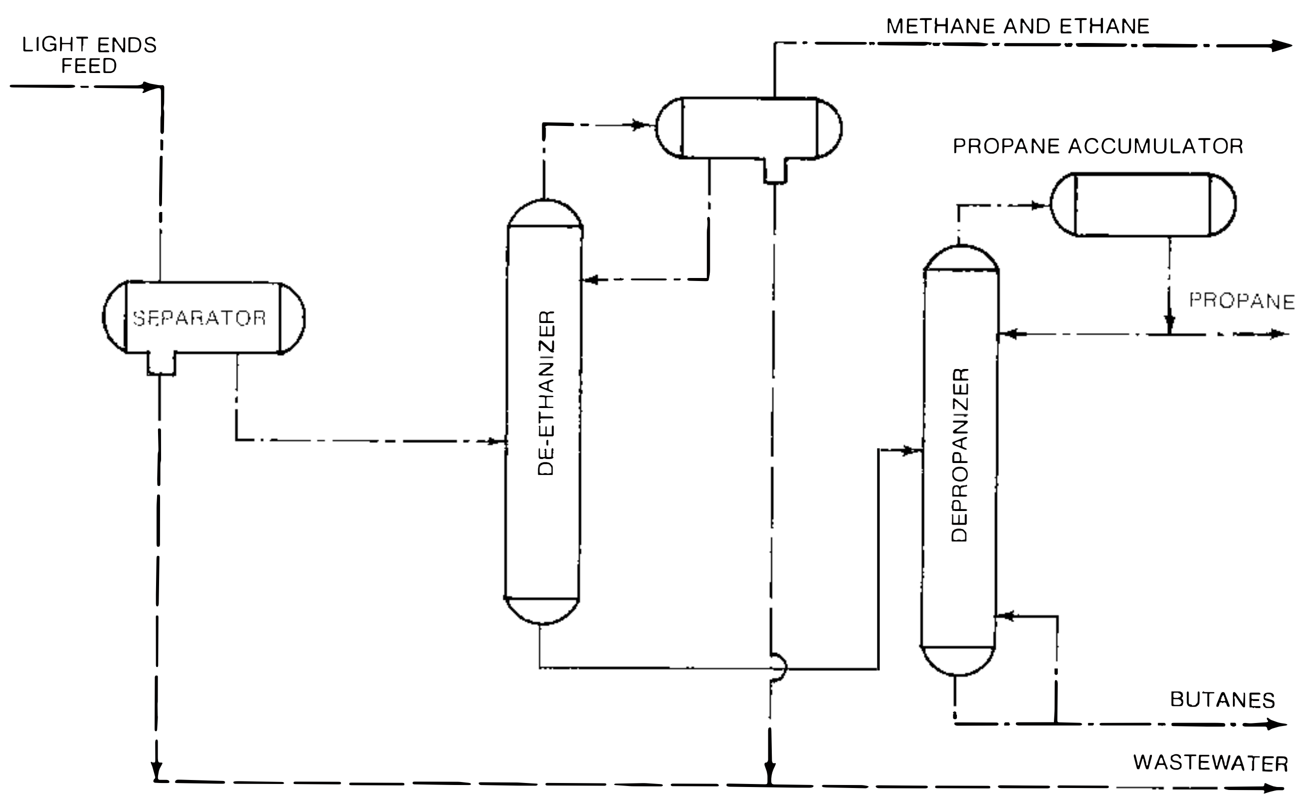


Figure 41. Light Ends Recovery Unit.

NOTE: The legend appears on Figure 27.

III. Acid Gas Treating Unit

H_2S and CO_2 are termed acid gases, and a fuel gas stream containing these compounds is called sour gas. Sour gas is produced during a number of refinery processes, including catalytic cracking and hydrotreating. Refinery-produced gas can be expected to be sour; it is sometimes necessary to treat the gas to remove H_2S before it can be used as a refinery fuel in order to comply with environmental standards.

Acid gas is typically removed by absorption in alkaline solution. A typical acid gas treating system is shown in Figure 42. The alkaline material is chosen so that the chemical bond formed during absorption can be broken by heating to regenerate the solution. Absorption solutions containing acid gas are termed "rich" and the regenerated solutions are termed "lean." The fact that these solutions differ allows for several acid gas treating processes. The most widely used absorbents are monoethanol amine and diethanol amine. The processes differ only in the absorbents used.

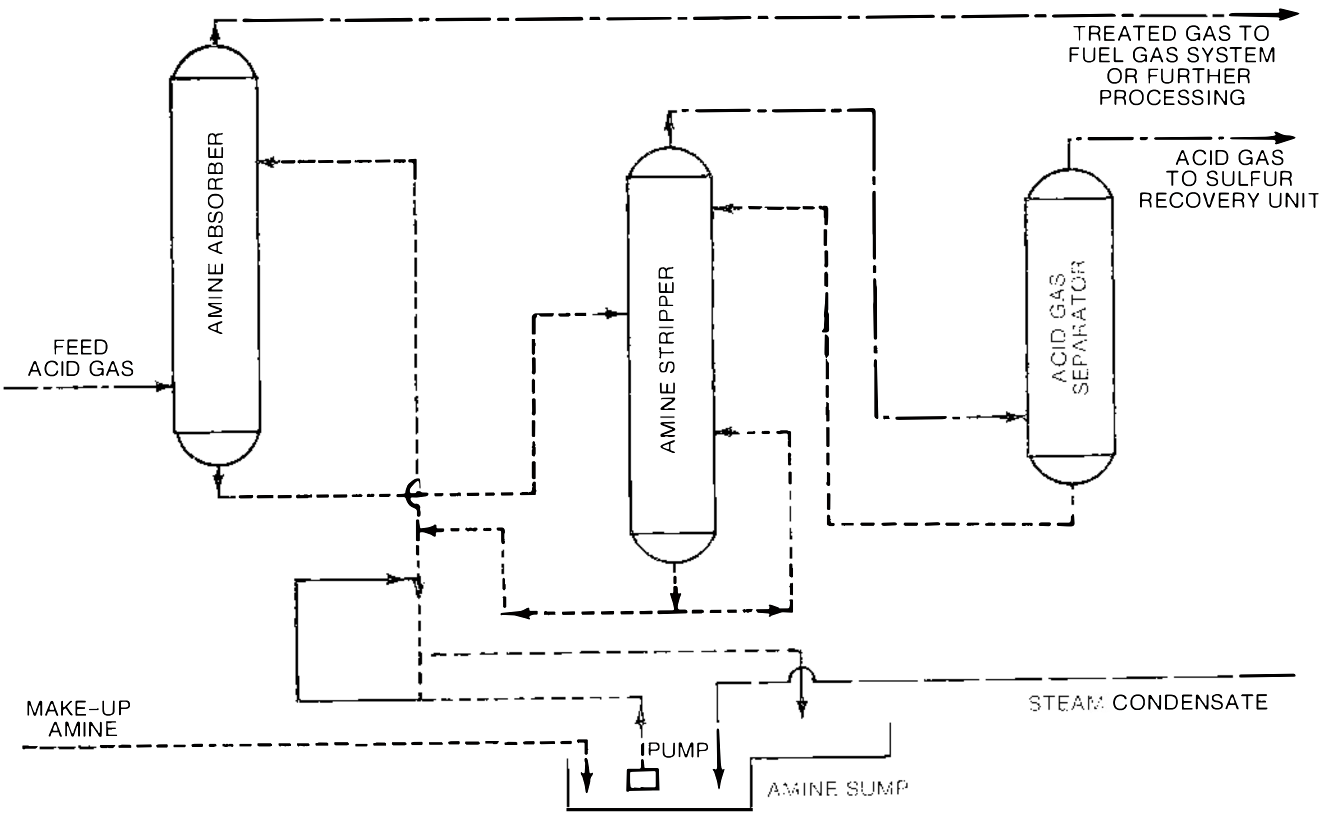


Figure 42. Acid Gas Treating Unit.

NOTE: The legend appears on Figure 27.

IV. Sulfur Recovery Unit

The sulfur recovery plant is used to convert H_2S to elemental sulfur. The most widely used recovery system is the Claus process, which uses both thermal and catalytic conversion reactions. Sulfur recovery operations are discussd in detail in the Environmental Considerations section of this chapter.

V. Tail Gas Treating Unit

Numerous processes are available to treat tail gas from the Claus sulfur recovery unit. They include the Beavon-Stretford, Shell Claus Off-Gas Treatment (SCOT), and Wellman-Lord processes. Tail gas treating processes are discussed in detail in the Environmental Considerations section of this chapter.

VI. Sour Water Stripping Unit

Water containing sulfides and ammonia is called "sour water condensate." Refinery operations produce sour water from processes such as catalytic cracking and hydrotreating and whenever steam is condensed in the presence of gases containing H_2S. Sour water usually contains H_2S, NH_3, and small amounts of phenol and other hydrocarbons. Sour water stripping is used to reduce H_2S and NH_3 levels.

There are many different stripping methods, but most of them involve the downward flow of sour water through a trayed or packed tower while an ascending flow of stripping steam or gas removes the H_2S and NH_3. A typical sour water stripper is shown in Figure 43. The acid gases from the process are sent to the sulfur

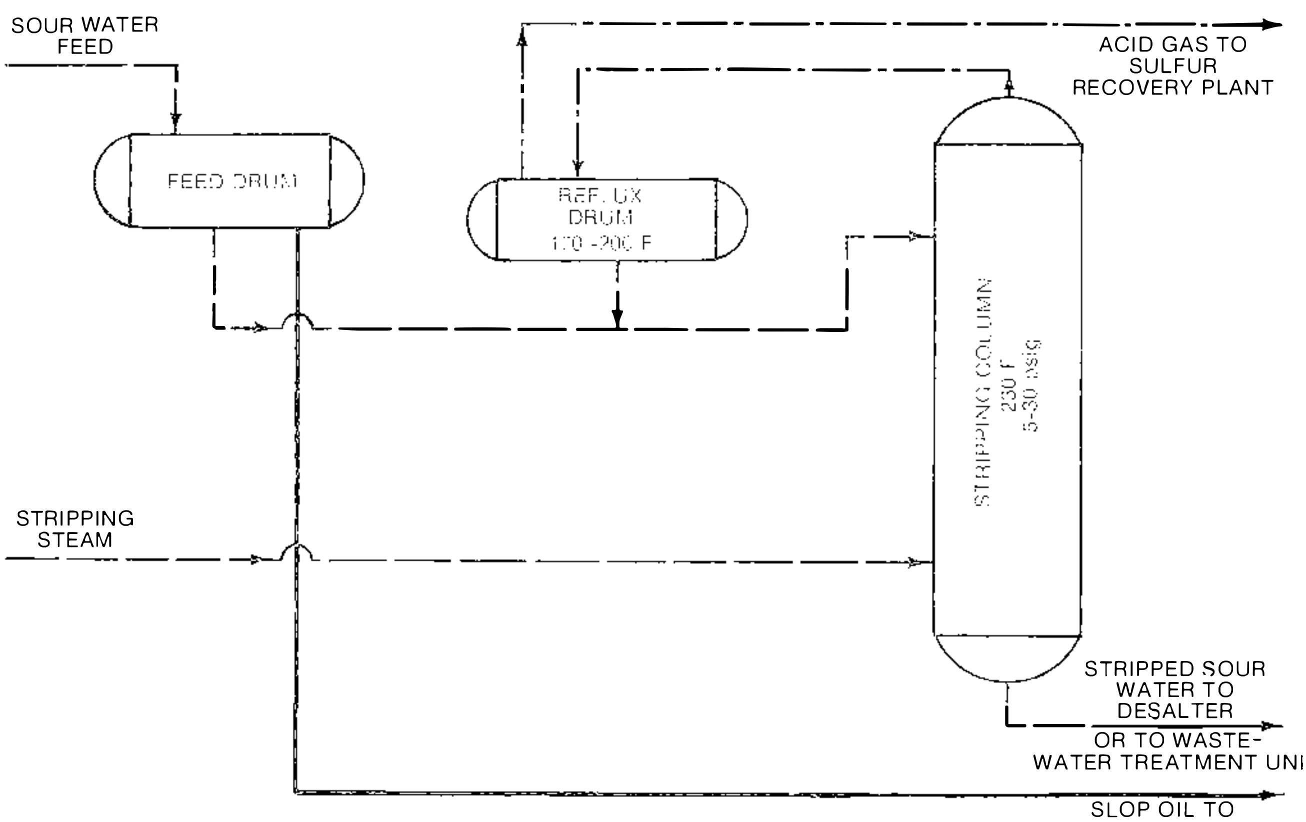


Figure 43. Sour Water Stripping Unit.

NOTE: The legend appears on Figure 27.

recovery unit, stripped sour water goes to the desalter, and recovered oil goes to the slop oil recovery tank. A more detailed discussion of sour water stripping is contained in the Environmental Considerations section of this chapter.

VII. Wastewater Treatment Unit

Treatment of refinery wastewater to remove contaminants typically involves a variety of treating processes. The proper treatment combined with in-plant source control of wastewater provides a quality effluent suitable for discharge. A typical wastewater treatment unit may contain an equalization basin, an API separator, slop oil recovery equipment, a dissolved air flotation (DAF) unit, biological treatment, and filters. Wastewater treating equipment is discussed in detail in the Environmental Considerations section of this chapter.

REFINERY OFFSITE FACILITIES

Although the offsite equipment and facilities do not enter directly into the operations of the various process units, they are critical to the operation of the refinery.

I. Storage Tanks

Tankage in a refinery is required for storage of crude oil and intermediate and finished products, in both liquefied and gaseous forms. The requirement for tankage will vary, depending upon such factors as the storage levels for crude oil, the number of products and their storage levels, and the variety of blending and intermediate stocks.

Many tank designs are available for storage of liquid products and gases. The type of storage required will depend primarily upon the vapor pressure and pour point of the material. To minimize hydrocarbon emissions, products such as motor gasoline are stored in floating roof tanks. A number of tanks are equipped with steam coils and are insulated to store products such as highly viscous oils and asphalt. Products with low vapor pressure are stored in fixed roof tanks.

II. Steam Generating Systems

Steam is needed for many of the refinery processes. These include steam distillation, steam stripping, steam-jet eductors for vacuum distillation, steam turbines for driving blowers and other equipment, steam reforming to produce hydrogen, and power generation.

Steam is provided to the refinery processes through either a closed loop or an open loop system. In the closed loop system, the steam generated yields its heat to the product process streams in

heat exchangers by condensation. The steam condensate is then returned to the boiler. The open system uses steam for stripping in fractionating towers, for example, and the steam lost is made up by feedwater to the boiler.

Figure 44 shows a typical steam generation system. Fresh make-up water is first treated by softening and de-ionization to achieve the desired feedwater quality. After treatment the fresh water is preheated with the boiler blowdown and pumped to the de-aerator to remove dissolved oxygen. The treated make-up water is then mixed with the returned condensate and pumped to the boiler.

III. Flare and Blowdown Systems

The flares are the main safety valves for the refinery operation. They safeguard personnel and protect the plant from damage during process unit upsets and plant emergency conditions, such as power failures and extreme pressure conditions in process units. To protect the refinery equipment from damage, and for operating safety, pressure relief valves are set below the design pressure of the equipment.

Basically, a flare system consists of piping to collect the gases, devices to remove entrained liquid, and a terminal burner operating in the open with no provision to recover heat or to treat the combustion products. As shown in Figure 45, the system consists of the following elements:

- Flare header from the process units
- Knockout drums to remove and store condensable and entrained liquids
- Proprietary seal, drum, or purge gas to prevent flashback
- Flare stack to raise the burner to the desired height
- Gas pilots and an igniter
- Steam injection for smokeless flaring.

During normal operations, when none of the systems are releasing hydrocarbons, purge gas is required to maintain velocity in the flair stack to prevent backflow of air into the flare system to avoid explosions. Under emergency conditions, the released hydrocarbons flow from the flare header to the knockout drum, where entrained liquids are separated. The vapors from the drum flow through a liquid seal to the flare and are burned. Steam is injected into the flare gas or flame to provide a smokeless exhaust. The liquid is pumped to the slop oil system for reprocessing. This system avoids the uncontrolled discharge of hydrocarbons to the wastewater treatment system, the release of hydrocarbon to the air, and the loss of valuable petroleum material.

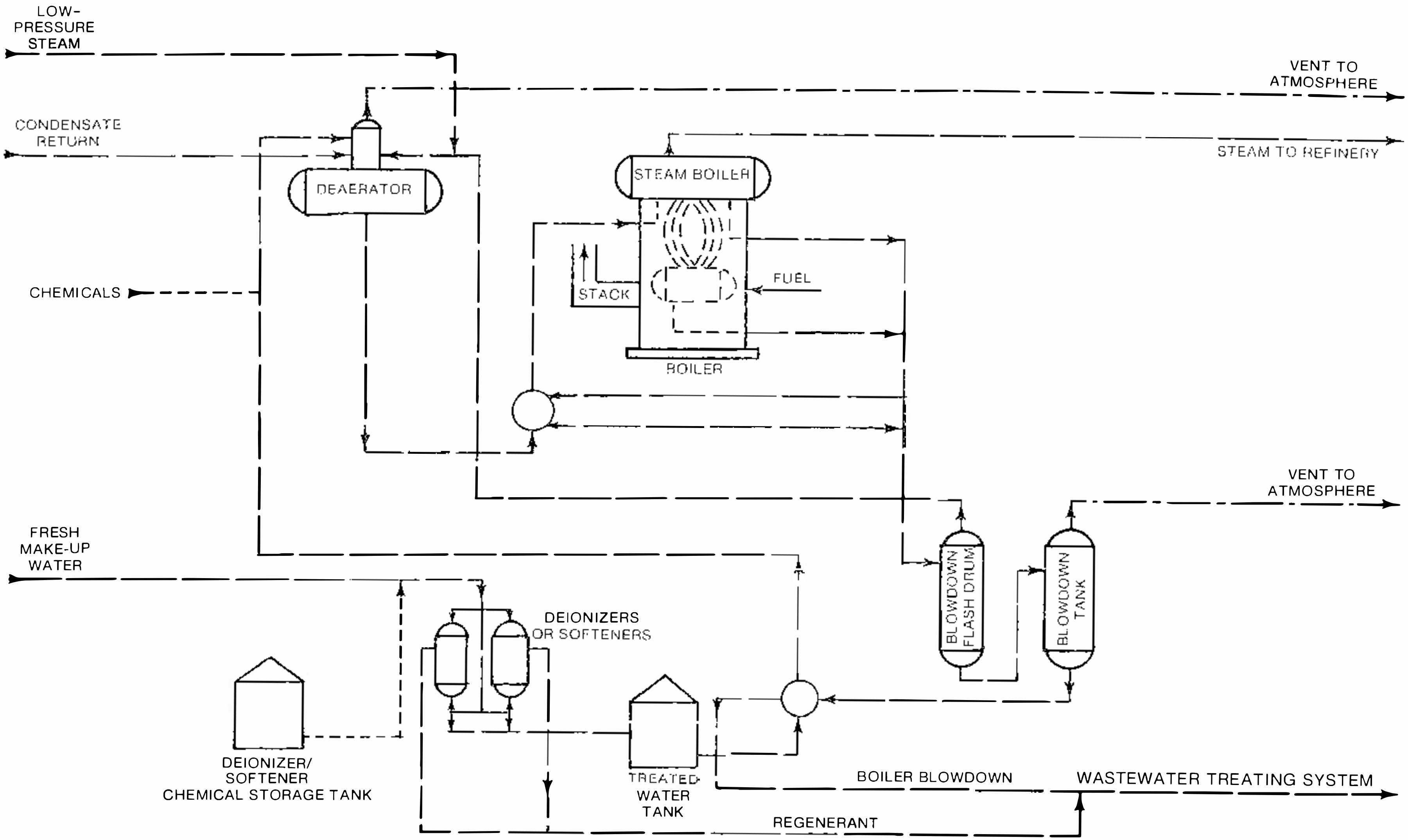


Figure 44. Steam Generation System.

NOTE: The legend appears on Figure 27.

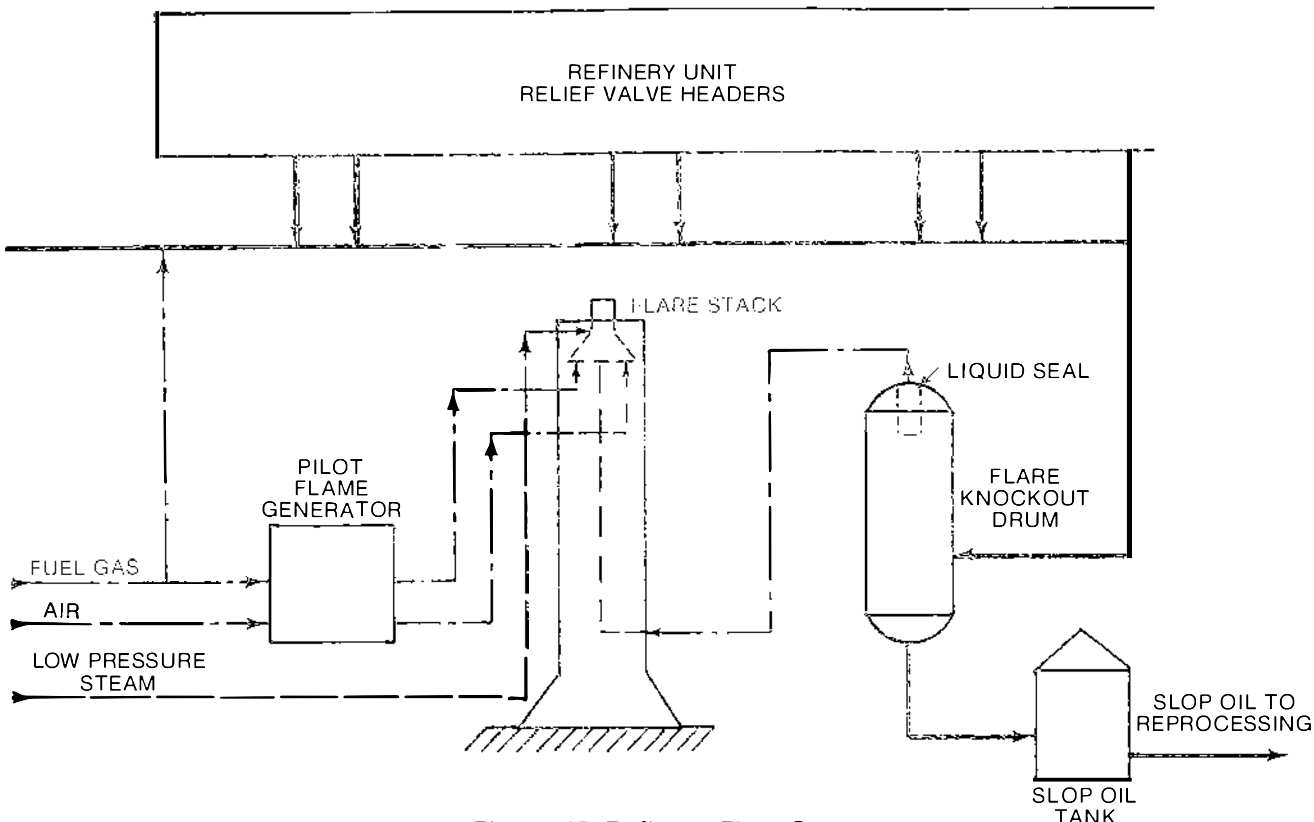


Figure 45. Refinery Flare System.

NOTE: The legend appears on Figure 27.

Several types of flares are available, but all must operate safely and efficiently under widely varying conditions. The flow of waste gas can range from almost zero, when the only discharges are leakages from relief valves, to very large quantities in emergencies. Further, the required capacity of the flare varies with the crude oil throughput, the complexity of refining, and the capacity of the recovery system.

Since it is difficult to design a single flare to handle efficiently such extreme variations in flow, many systems have two flares. One flare is designed to provide smokeless combustion for the normal flow, and the other is activated to handle excess flow resulting from an emergency. There also may be flares designed to serve single specialized units.

IV. Cooling Water Systems

Water is typically used for removing heat from the various product streams. Fans are employed, however, for air cooling in some refineries to reduce water requirements and effluent volume. Figure 46 is an illustration of a typical water cooling system. Most systems are recirculating systems similar to the one shown in the diagram. Water from the cooling tower basin is circulated to heat exchangers where it picks up heat and returns to the top of the cooling tower. The tower, which is open to the atmosphere, contains a wood or plastic packing, which provides the surface

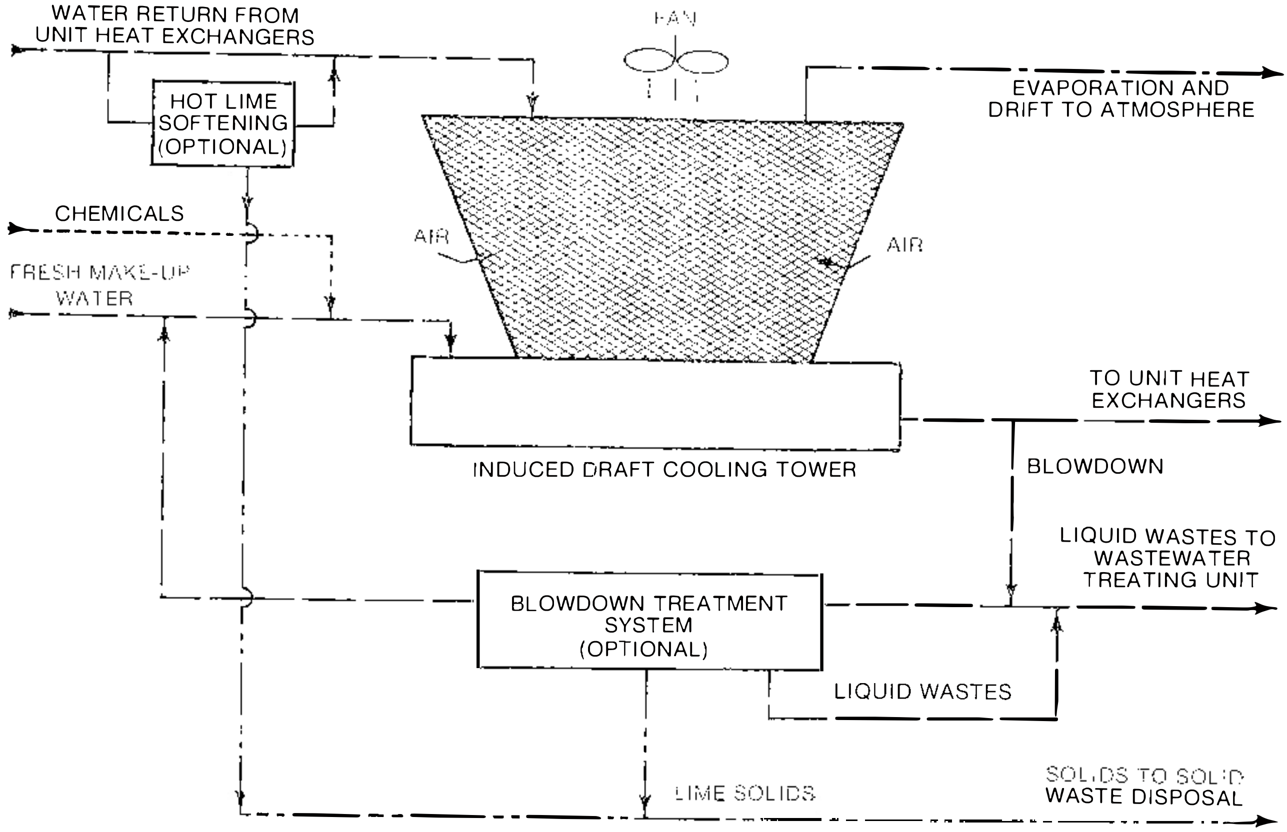


Figure 46. Recirculating Water Cooling System.

NOTE: The legend appears on Figure 27.

necessary to maintain high heat-transfer efficiency. Air is either forced or flows by natural convection countercurrent to water, and the water is cooled by evaporating a portion of the water.

V. Receiving and Distribution Systems

Receiving and distribution systems are a combination of pumps, pipelines, storage tanks, barges, tankers, tank cars, tank trucks, and loading and unloading facilities. These facilities are used to receive and collect materials, crude oil, and products, and to distribute final products to the consumer by pipeline to trucks, tank cars, barges, and tankers.

VI. Refinery Fire Control Systems

Most refineries are completely equipped and maintain trained personnel to fight a fire should one occur. The refinery fire water system is a separate system with designated storage, pumps, and piping. Process areas maintain permanent installed water spray devices called monitors, which provide virtually instantaneous firefighting capability. Sewer systems, particularly those in process areas, are designed with seals, covers, traps, fire baffles, etc., to prevent the spread of fire between areas. Refineries maintain a foam system, fire trucks, and other firefighting equipment. Appropriate training is an essential ingredient of fire protection.

AIR

The continuing development of national, state, and local legislative and regulatory requirements governing air pollution control, from 1963 to the present, have substantially affected oil refining operations. In particular, the development of provisions for detailed pre-construction review of all major stationary sources of air pollution has introduced a highly complex and time-consuming set of procedures.

I. Standards and Regulations -- Clean Air Act

The provisions of the Clean Air Act dealing with air quality management, National Ambient Air Quality Standards (NAAQS), Prevention of Significant Deterioration (PSD), and nonattainment affect the refining industry and are discussed in Chapter One. Other provisions that impact the refining industry are New Source Performance Standards (NSPS) and State Implementation Plans (SIPs).

A. New Source Performance Standards

Petroleum refineries are an industrial category covered by federal NSPS, which are national standards for new major industrial sources. A new refinery or expansion is affected by three NSPS (one for petroleum refineries[2] and two for liquid petroleum storage vessels) and may be affected by the NSPS for fossil fuel-fired steam generators and stationary gas turbines.[3]

The NSPS for petroleum refineries are applicable to FCCU catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants producing more than 20 long tons per day. A summary of the NSPS is shown in Table 32.

The NSPS for storage vessels for petroleum liquids are applicable to vessels having a capacity of 40,000 gallons or more and utilizing floating roofs and/or a vapor recovery system to control hydrocarbon emissions depending upon the true vapor pressure of the hydrocarbon stored.

B. State Implementation Plans

The Clean Air Act directed states to develop SIPs containing the control efforts required to achieve compliance with the NAAQS. Each SIP is required by law to include a construction permit program for any major emitting facility to assure that NAAQS are achieved and maintained.

TABLE 32

New Source Performance Standards for Petroleum Refineries*

Affected Facility	Pollutant	Maximum Allowable Emission Level	Monitoring Requirement†
Fluid Catalytic Cracking Unit Catalyst Regenerator	Particulate§	1.0 lb/1,000 lb of coke burn-off	No Requirement
	Opacity	30% (6 minute exemption per hour)	Continuous
	CO	0.05% by volume	Continuous
Fuel Gas Combustion Devices	SO_2	Equivalent of 0.10 grains of H_2S per dscf¶ in fuel	Continuous
	H_2S	230 mg/dscm**	Continuous
Claus Sulfur Recovery Plants (Plants greater than 20 long tons per day)	SO_2	0.025% (at 0% oxygen)	Continuous
	Reduced sulfur compounds	0.030% (at 0% oxygen)	Continuous
	H_2S	0.0010% (at 0% oxygen)	Continuous

*Source of data: Code of Federal Regulations, 40 CFR 60, Subpart J.

†Continuous monitors are used to determine excess emissions only.

§Where the gases are discharged through an incinerator or waste heat boiler in which an auxiliary fuel, liquid or solid fossil, is used, particulate matter in excess of 1.0 lb/1,000 lb of coke burn-off may be emitted at a rate of 0.1 lb/million Btu of heat input or less.

¶Dry standard cubic foot.

**Milligrams per dry standard cubic meter.

II. Impact of Refinery Emissions in the Environment

A. Progress Made Through 1979

Petroleum refineries may be large stationary sources of NO_x, CO, hydrocarbons, and SO_x. Typically, however, refinery emissions have been subject to control technology. Environmental Protection Agency (EPA) emission data for refineries (Table 33) estimate that total suspended particulate (TSP) emissions have decreased 29 percent and CO 57 percent from 1970 to 1979. Emissions of SO_x, NO_x, and volatile organic compounds (VOC) were

estimated to increase 10 percent, 10 percent, and 33 percent, respectively, during this decade. However, when it is recognized that crude oil runs increased 35 percent during this period, from 10,870 thousand barrels per day (MB/D) in 1970 to 14,648 MB/D in 1979, some very substantial reductions were made in emissions per barrel of crude oil run. These per barrel reductions were 50 percent for TSP, 19 percent for SO_x, 18 percent for NO_x, and 68 percent for CO (Table 33).

TABLE 33

Estimates of Total Emissions from Refineries -- 1970 and 1979

	1970	1979	Percentage Change
Emission Estimates in Thousand Metric Tons Per Year*			
TSP	70	50	-29
SO_x	620	680	+10
NO_x	310	340	+10
VOC	720	960	+33
CO	1,990	850	-57
Emission Estimates in Metric Tons Per Million Barrels of Crude Oil Run†			
TSP	18	9	-50
SO_x	156	127	-19
NO_x	78	64	-18
VOC	181	180	0
CO	502	159	-68

*Source of data: Environmental Protection Agency, National Air Pollutant Emission Estimates, 1970-1979, 1981.

†Emission estimates in metric tons per million barrels of crude oil run based on 1970 = 10,870 MB/D, 1979 = 14,648 MB/D. Source of data: American Petroleum Institute, Basic Petroleum Data Book, 1981.

B. Comparison of Emission Levels

An individual refinery may be a large stationary source of a particular pollutant. When compared to total emissions from all sources, however, emissions from petroleum refining operations are a very small fraction of the total emissions, as illustrated in Figure 47.

Petroleum refinery emissions are expected to remain rather constant in the 1980's, as crude oil runs are expected to decrease. The 1980 National Petroleum Council (NPC) study, Refinery Flexibility, describes actual refinery crude oil runs for 1978, the peak crude oil run year, and projected runs to 1990 as shown in Figure 48. Current forecasts indicate that even lower crude oil runs are expected in the future. Despite negative growth projections, refineries will continue to require large capital expenditures for new and modified facilities for upgrading poorer quality crude oils and other feedstocks.

III. Impact of Regulations on the Cost and Availability of Petroleum Products

A. Impact on Cost

Capital expenditures amounting to $3.7 billion have been devoted to air pollution abatement projects in the manufacturing segment of the petroleum industry for the 1971-1980 period. The annualized cost of air pollution abatement facilities has been estimated at $1.3 billion for 1980. This amounts to more than $250 for each barrel of daily product capacity.[4]

Much has been accomplished by these expenditures, including the reduction in emissions per barrel of crude oil processed as described previously. Emissions from oil refineries represent only 0.5 percent of total TSP emissions, 2.8 percent of SO_x, 1.5 percent of NO_x, 3.9 percent of VOC, and 0.9 percent of CO (Figure 47). These large expenditures on an industry segment that represents such a small fraction of the total emissions, when it is also recognized that the emissions from the petroleum sector are already tightly controlled, indicates that further controls are not cost effective.

Nevertheless, the Clean Air Act requirements impose large uncertainties in the planning and development of facilities and have the effect of increasing project risk and costs. Chevron U.S.A. testified before the U.S. House of Representatives Subcommittee on Health and Environment in 1981 that the addition of a sulfur recovery unit at Chevron's Perth Amboy, New Jersey, refinery was delayed 18 months because of EPA's indecision regarding whether or not a PSD permit was required for the project EPA eventually decided that no permit was required because the recovery unit reduced overall refinery sulfur dioxide (SO_2) emissions from 700 tons per year to 162 tons per year. This delay resulted in the addition of about $2.3 million to the $40-50 million original project cost estimate and allowed 800 tons of SO_2 to be emitted during the period of delay.

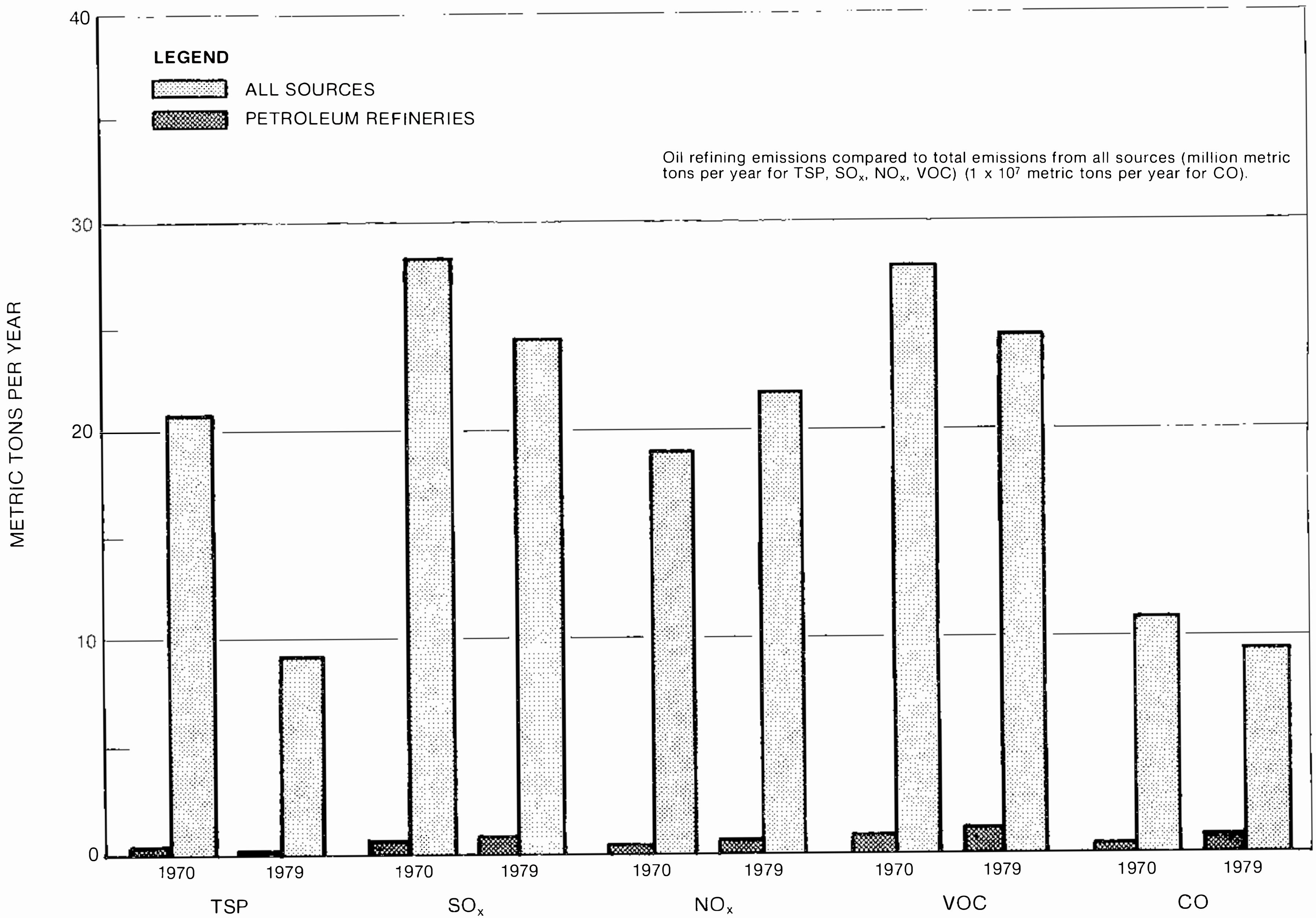


Figure 47. Emission Comparison Estimates—1970 and 1979.

SOURCE: Environmental Protection Agency, *National Air Pollutant Emission Estimates, 1970-1979,* 1981.

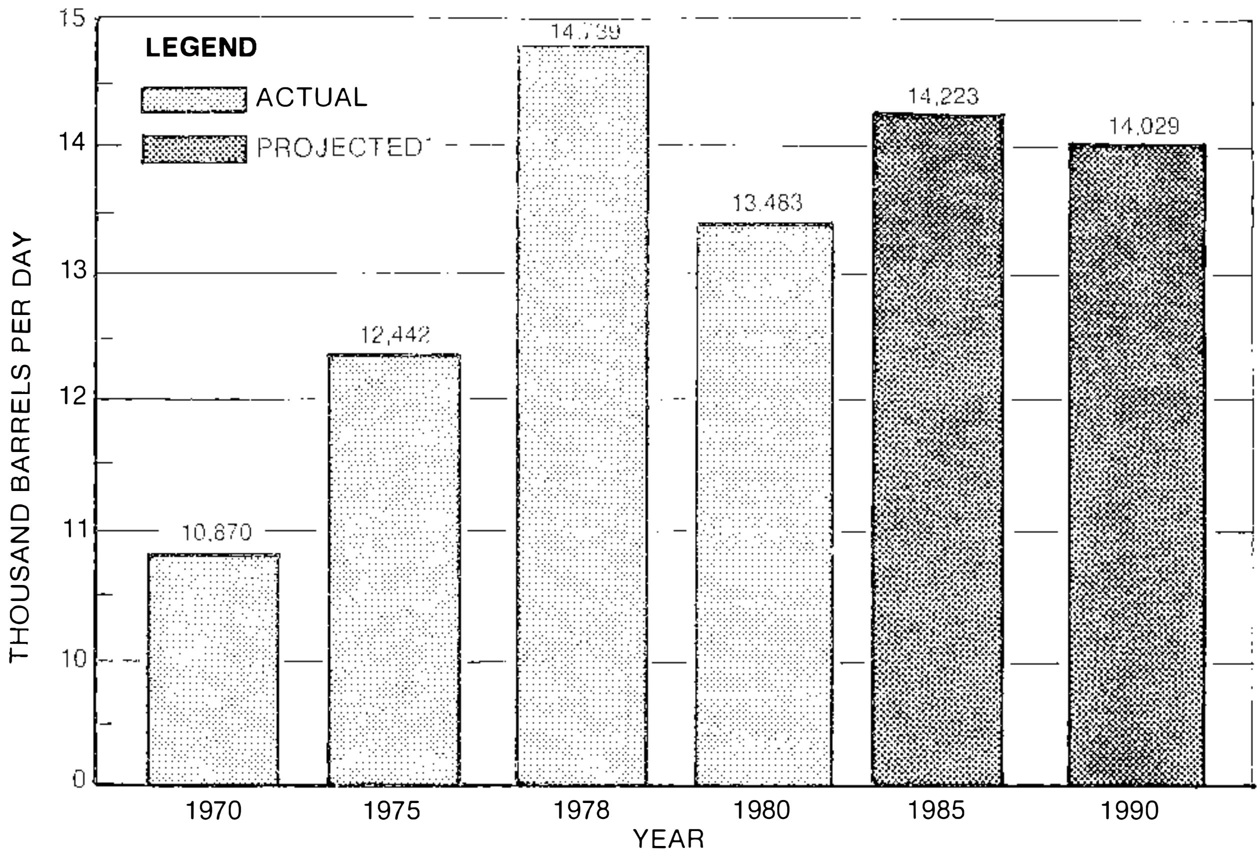


Figure 48. U.S. Refinery Crude Oil Runs.

SOURCE: Actual crude oil run data from American Petroleum Institute, *Basic Petroleum Data Book, Petroleum Industry Statistics*, 1981; projected crude oil run data from National Petroleum Council, *Refinery Flexibility*, December 1980.

1. Lowest Achievable Emission Rate

New sources in nonattainment areas must comply with control technology requirements to ensure Lowest Achievable Emission Rate (LAER). LAER is defined as the most stringent limitation achieved in practice anywhere. In no event can LAER require controls less stringent than applicable NSPS. Unlike Best Available Control Technology (BACT) applied to PSD areas, LAER does not take economic factors into account. LAER determinations may require the "transfer of technology" from one source category to another. The National Commission on Air Quality determined the LAER concept to be impractical and recommended abandonment.[5]

2. Offsets Greater than One-to-One

To demonstrate "reasonable further progress" toward attainment, a new or expanded source must obtain emission offsets from other existing sources in the area. These offsets must be greater than one-to-one for each pollutant emitted. Generally, offsets are acceptable if obtained from the immediate vicinity. However, since VOC and NO_x can have impacts on areas at great distances from the source, offsets for these pollutants can be obtained over a broad area (usually the entire Air Quality Control Region). If the proposed offsets are obtained from sources located far from the new

source, a greater offsets ratio is generally required. In these cases, the applicant must demonstrate that nearby offsets were investigated, and that reasonable alternatives were unavailable.[6]

B. Impact on Availability

In the 1971-1980 period, petroleum refineries operated at 90 percent or less of capacity, averaging about 88 percent. Thus, overall there has been no shortage of products due to refining capacity limitations. Delays in permitting new facilities at worst resulted in local dislocations in petroleum supplies, which were remedied by shifting distribution patterns. Local product shortages replenished by shifting sources typically add costs to the product marketed.

C. Case Histories

Adverse impacts of the Clean Air Act are described in a 1981 study by Environmental Research and Technology, Inc., in which 150 companies participated and 92 case histories were verified and documented. Various combinations of three general problems were found in almost every case study report: undue uncertainty in project planning; avoidable delays in decision-making by review agencies; and unjustifiably stringent control technology requirements without commensurate air quality benefits.

Analysis of the case study reports indicated several adverse effects of the Clean Air Act on national energy, economic, employment, and environmental goals. Among the major adverse effects evidenced in many of the case studies are the following:

- Reduced development of domestic energy resources
- Loss or delay of employment and local tax revenues
- Project cancellation or relocation
- Adverse effects on small companies
- Delayed air quality improvements because of Clean Air Act requirements.

The principal causes of the excessive costs, uncertainties, delays, and excessive control requirements were categorized as follows:

- Complex and inflexible statutory requirements for regulatory reviews, including:
  - Overlapping federal and state reviews
  - Complex regulations subject to frequent change during review proceedings
  - Lack of flexibility by review agencies in their interpretation of regulatory requirements

- Operational problems within the review agencies (e.g., work overload, personnel turnover, inadequate communications).

- Implementation of the PSD program, including:
  - Disputes concerning PSD increment allocation
  - Lengthy and uncertain negotiations concerning case-by-case BACT determinations
  - Lengthy pre-application ambient monitoring requirements.

- Impractical nonattainment area requirements, including:
  - Excessively stringent (and changeable) LAER determinations
  - Unavailability of emission offsets.

- Technical difficulties, including:
  - Excessively conservative air quality modeling requirements
  - Use of unverified models to determine emission control requirements.

Specific case history examples of refinery projects supportive of these conclusions follow:[7]

1. Case History No. 1

An oil company initiated ambient air quality monitoring programs in the vicinities of two midwestern refineries and one eastern refinery. The objective of these programs was to collect data that would be needed for PSD permits, although no specific commitment to expand or modify any of the three facilities had yet been made. It was believed by the company that early completion of the monitoring would eliminate a 15- to 18-month delay at a later date when timing for one or more projects could be critical.

The company's management requested that preliminary work be conducted in January 1979 to determine costs of such a monitoring program. Initial contacts to state and federal agencies were made in February 1979, and a request for bids was sent to five contractors. In May, the contract to perform the monitoring was awarded and preparation was started on the work plans to be submitted to the appropriate agencies (two states and EPA regions). Model calculations were made to determine the locations of expected maximum short-term and long-term SO_2 and particulate concentrations around each facility. These calculations served to assist in

determining the appropriate number and deployment of monitoring stations.

Work plans describing the proposed monitoring programs were submitted during August and September. The work plan for one of the refineries was quickly approved and monitoring site selection and acquisition began. Two sites were selected, but local politics eliminated both. One alternate site was identified immediately, but an acceptable second site was not located until the end of December.

EPA Region V refused to approve the monitoring plans for the other two refineries, which are in a different state. In its denial, EPA cited 10 issues requiring resolution before approval could be granted, although at a subsequent meeting in November half of these topics were dropped. The company submitted an addendum to these work plans and final agency approval was obtained in January 1980. Two monitoring sites were located near each refinery, and the data collection had commenced at all locations by the end of February.

Three important problems are identified in this case history. First is the time delay associated with the monitoring requirement. In this case, 29 months elapsed between the decision to monitor and the expected completion of the monitoring report. The second problem is the cost of monitoring. Approximately $750,000 was spent to monitor at six sites (two sites at each of three locations). Both of these factors have the potential to cause significant increases in the refinery modification costs.

The third point is that the air quality monitoring stations operated by state and local agencies were located within about two miles of each plant site. Nevertheless, state and federal authorities determined these existing sites were inappropriate to assess the impacts of the facilities in question.

2. Case History No. 2

In January 1980, a refinery began consideration of potential modifications and began to make preparations to apply for the necessary environmental permits. Some changes in pollutant emissions would likely occur due to these modifications, but the actual magnitude of the change could not be determined until an emission baseline for the existing refinery was established.

Meetings with the appropriate state agency were held in February and March in an attempt to establish guidelines for setting baseline emissions for the refinery. Both the refinery personnel and the agency were uncertain as to how to proceed with this difficult task. Refineries are extremely complex sources with many individual pollutant release points. Furthermore, an absolute operational requirement of such facilities is the flexibility to respond rapidly to the product demands of the market, which results in highly variable emissions. This variability is often further

complicated by the changing availability of crude oil feedstocks and fuels for internal consumption, e.g., natural gas.

As a result of these complexities and difficulties in interpreting the Clean Air Act's intentions on this point, a series of data requests from the state agency was received over a period of almost a year. During this period, revisions to the Clean Air Act sections on New Source Review were promulgated, further complicating the process.

In February 1981, the agency formally refused the company's proposed definition of baseline emissions. Only in mid-1981 was progress made toward resolving this issue.

The levels of analysis, monitoring, and pollution control required for modifications to existing sources depend on the anticipated net increase in emissions associated with the modification. As currently formulated, the Clean Air Act regulations on this point define the increase in emissions of any pollutant from a baseline level representing average operations during the two years prior to the start of construction. For a source with highly variable emissions, such as a refinery, the arbitrary two-year baseline period can penalize sources operating at less than full capacity during this period, since the lower the baseline level used, the larger the difference in emissions that will be attributed to the modification. As an illustration of this point, consider a refinery that during the two years before a proposed modification had had a larger than normal supply of natural gas to fire heaters and other equipment. If the plant configuration after the modification is to be permitted for the use of oil-fired equipment, the percentage increase in SO_x emissions that would be used to characterize the modification would be much greater than if oil had been burned before the modification.

In this case, well over one year was spent by the company in a cooperative effort with the state agency to attempt to define baseline emissions. The rules for such cases need to be reviewed and possibly changed.

3. Case History No. 3

A major refinery planned a $500 million modernization of a series of facilities to enable them to manufacture high viscosity index lubricating oil. The new equipment would replace 40-year-old units and be more energy efficient, more environmentally acceptable, and be further removed from public streets and homes. There would be no change in the amount of crude oil going through the refinery. The cumulative emission changes of SO_2, NO_x, CO, VOC, and particulate matter since 1977 would be negative. The applicant voluntarily would control emissions to ensure these levels.

The project is subject to the Clean Air Act construction ban applicable to major sources in nonattainment areas of states that do not have an approved SIP. As part of the construction, the

company must drive approximately 2,000 pilings. Of these, 50 are located near existing high-pressure reactor vessels. These are shut down in a very complicated sequence for maintenance approximately every two years; a maintenance shutdown occurred in March 1981. The company called EPA to review the pile driving in light of the construction ban. EPA did not appear to be fully cognizant of the regulations and was unwilling to take any steps to permit the driving of the piles. EPA could not determine what constituted the "installation" under the dual source definition, as it could not determine the extent of the "installation" of which the pilings were part, and thus denied the request. EPA therefore responded by saying that it had not been afforded any discretion by Congress in enforcing the construction restriction. The statutory language clearly provides that the restriction on major construction is automatic and mandatory.

In this case, a construction project that would actually reduce emissions was held up because the state and EPA could not come to terms on an SIP revision. The SIP revision was transmitted to EPA on January 14, 1980. After receiving public comments on the proposals and after more than one year of delay, EPA still has not approved the SIP.

The lack of discretion allowed by law for the agencies does not permit unusual circumstances to be taken into account. Delays such as those encountered in this project are wasteful. The new equipment would reduce emissions at the refinery and be more energy efficient than existing equipment. It would increase annual city and county tax revenues by $7 million and would provide 1,200 construction jobs and 50 permanent jobs for the area.

4. Case History No. 4

A major refinery planned a modification to process different grades of crude oil. It was considered a major modification for SO_2 and particulate matter and thus subject to the PSD regulations.

A monitoring program was designed, based on very early project plans. The final program was required to be much more rigorous and comprehensive in order to cover possible design changes. Negotiations over the monitoring program took several months and, in effect, were a pre-PSD permit. Cost for the program was approximately $400,000. The total time period to institute and carry out the monitoring was 14 months.

A major problem in the analysis portion of the application was a requirement that secondary emissions be addressed (in this case, ships at the port). Because it is impossible to predict or dictate the types of tankers to call at the port, certain assumptions had to be made. An agreement was reached to model a certain type of ship and fuel. Modeling techniques are usually applied to stationary sources, not mobile sources. (Although mobile source models are available, they are not applicable to large sources such as

ships.) In addition, the smokestacks on ships are usually short and wide and are subject to a significant amount of aerodynamic downwash. The errors associated with this type of analysis are great and to base final permit conditions on such an uncertain basis is a questionable practice.

No violations of PSD increments were predicted by the modeling. However, it showed a 96 percent consumption of the Class I 3-hour SO_2 increment at the Breton Wilderness 50 kilometers away. It also predicted a 98 percent consumption of the local Class II 24-hour SO_2 increment. In both cases, vessel emissions were the major cause, contributing to three-quarters and almost all of the Class I and II increments, respectively. Since this increment consumption would preclude any future development, a major concern of the state of Mississippi, the company agreed to "refund" portions of each increment if necessary. These "refunds" would limit consumption to no more than 65 percent of the Class I and 50 percent of the Class II increments.

The company believes that the PSD increments, themselves stringent constraints, were considered absolute limits and, in effect, became land-use criteria. The necessity of pre-approval of a monitoring plan was, in effect, a pre-permit. The application of modeling techniques to a source of emissions secondary to the modification became the limiting factor.

The total cost of the entire PSD permit is estimated to be \$700,000. A total of 16 months passed after monitoring was completed before the permit was approved. The total time from project inception to permit approval was 32 months. The total project cost is estimated at \$1 billion; at current market and inflation rates, the amount represents almost \$300,000 for each day the project was delayed.

5. Case History No. 5

In early 1979, a major oil refiner informed EPA that it wanted to modify an existing sulfur recovery plant at its refinery to improve performance and satisfy state pollution control requirements. The planned improvements were designed to reduce SO_2 emissions by over 500 tons per year. Despite the emission reduction, EPA required the refiner to apply for a PSD pre-construction permit.

After months of effort by company engineers and an environmental consulting company, the oil refiner submitted a PSD permit application to EPA in June 1979. It required almost seven months of deliberation by EPA and a series of letters and telephone calls before EPA finally agreed in January 1980 that the permit application was complete. The changes made to the original permit application were inconsequential.

Matters then became more confused. In an exchange of more letters and telephone calls in May 1980, EPA sought to determine how the Agency's administrative order, issued in January 1980,

partially staying its 1978 PSD regulations, would affect the company's PSD permit application. Finally, in July 1980, EPA informed the company that its project was not subject to PSD review after all since it would reduce emissions from the plant.

It took one and a half years, $50,000, and several thousand hours of engineering, management, consulting, and government reviewers' time to determine and accept that the project would benefit the environment. Both the company and EPA personnel were victims of regulations so complex that they apparently defied consistent interpretation and action. To the company, the Agency personnel appeared to be overwhelmed by the complexity of the regulatory process, focusing on minor, inconsequential details rather than the basic issues at stake. Meanwhile, a company that wanted to improve pollution control equipment to reduce air pollutant emissions was hindered by EPA's difficulties in sorting out interpretive issues.

IV. Emission Sources and Their Control[8]

General sources of the most important air pollutants that may be emitted from refineries and the methods used to control them are summarized in Table 34. In the following sections the key air pollutant sources and means of control are developed in more detail.

A. Sources of Sulfur Compound Emissions

Some of the more important sources of refining emissions containing sulfur are given in Table 35. This list shows that there are many sources, some of which emit more than one type of objectionable compound. In any specific refinery, the sources that must be controlled will vary with the sulfur content of the crude oil, the allowable sulfur content of the products, and the refining processes employed.

B. Control of Sulfur Compound Emissions

A typical system to control the emission of sulfur compounds from a refinery consists of two complementary parts:

- Sulfur recovery to collect the sulfur removed from refinery products and by-products
- Waste product treating to control the direct emissions to the air.

The processes employed vary with the sulfur content of the crude oil, the specifications of the products, and the applicable air pollution control regulations.

1. Sulfur Recovery

There is a wide variety of sulfur compounds in crude oil ranging from gaseous H_2S to complex compounds of very high molecular

TABLE 34

Sources and Controls for Air Pollutants from Refineries

Air Pollutant	Refinery Sources	Control Processes
Malodorous Sulfur Compounds		
Hydrogen Sulfide Mercaptans Organic Sulfides	Evaporation, Leaks, Spills--All Process Operations	Disperse Incinerate, Flare Recover and Convert to Sulfur
Irritant Sulfur Compounds		
Sulfur Dioxide and Trioxide-Sulfuric Acid-Sulfates	Combustion--Catalyst Regeneration, Treating Processes	Disperse Scrub Convert to Sulfur
Nitrogen Oxides	Combustion--Furnaces and Internal Combustion Engines	Modify Combustion, Treat Flue Gas and Exhaust
Hydrocarbons	Evaporation, Leaks, Spills--All Process Operations	Incinerate, Flare, Minimize Losses, Optimize Operations
Asphyxiant Gases		
Hydrocarbons, Carbon Dioxide, Inert Gases	Leaks--Cleaning Process Equipment	Disperse, Purge, Ventilate, Flare
Toxic Gases		
Carbon Monoxide Hydrogen Cyanide	Catalyst Regeneration	Incinerate Flare
Inorganic Acids	Isomerization Catalyst	Neutralize
Hydrofluoric Hydrochloric	Alkylation--Cleaning Equipment	
Odors	Evaporation, Leaks, Spills--All Process Operations	Incinerate, Adsorb, Absorb, Neutralize, Oxidize, Mask
Particulates		
Smoke	Combustion--Flaring	Control Combustion
Process Dust	Treating--Catalyst Regeneration	Cyclone Separators, Electrostatic Precipitators
Mists	Cooling Towers--Steam	Filters and Scrubbers, Disperse
Noise	All Process Operations	Equipment Design -- Muffling Screening

SOURCE: American Petroleum Institute, "Atmospheric Emissions," Manual on Disposal of Refinery Wastes, 1977.

TABLE 35

Potential Sources of
Refinery Emissions of Sulfur Compounds

Refinery Source	Type of Sulfur Compound Emitted: Sulfur Dioxide/ Trioxide	Hydrogen Sulfide	Mercaptans/ Organic Sulfides
Combustion			
Boilers and Process Heaters	X		
Catalyst Regeneration	X		
Flares	X		
Decoking	X	X	X
Incinerators	X		
Conversion Processes			
Distillation		X	X
Cracking			
Catalytic	X	X	X
Thermal		X	X
Coking			
Delayed		X	X
Fluid	X	X	X
Hydrocracking		X	
Hydrodesulfurization		X	
Catalytic Reforming		X	
Treating			
Sulfur Recovery	X	X	
Sour Gas Treating		X	X
Regenerating Spent Solutions		X	X
Stripping Sour Condensates		X	X
Sulfur Dioxide Extraction	X		
Sulfuric Acid			
Alkylation			X
Treating	X		
Recovery	X		
Air Blowing		X	X
Anaerobic Digestion		X	
Miscellaneous			
Sour Crude and Product Tanks		X	X
Purging		X	X
Leaks and Spills		X	X
Relief Valves		X	X
Pumps and Compressors		X	X

SOURCE: American Petroleum Institute, "Atmospheric Emissions," _Manual on Disposal of Refinery Wastes_, 1977.

weights. Therefore, a typical sulfur recovery system employs the following steps:

- Removal of normally gaseous H_2S and methyl mercaptans by distillation
- Conversion of liquid sulfur compounds to gases by such processes as cracking, coking, reforming, and catalytic desulfurization with hydrogen
- Recovery of the gaseous sulfur compounds from the tail gas streams of the conversion and waste treating units
- Conversion of the recovered sulfur compounds to sulfur.

Recovery of H_2S and light mercaptans from the gases can be accomplished by a variety of heat regenerative methods. The raw gas is scrubbed with amine, sulfinol, or phosphate, all of which absorb H_2S at low temperatures. The rich absorbent solution is regenerated by reboiling and returned to the absorber. The concentrated H_2S is fed to the sulfur recovery plant.

2. Sulfur Recovery Plant

The sulfur recovery plant utilizes as feed the concentrated gas streams from the recovery unit and the sour water strippers usually located in the waste treatment section. The sulfur recovery plant converts H_2S to elemental sulfur.

The most commonly used sulfur recovery method is the Claus process (Figure 49). In this process, one-third of the H_2S in the

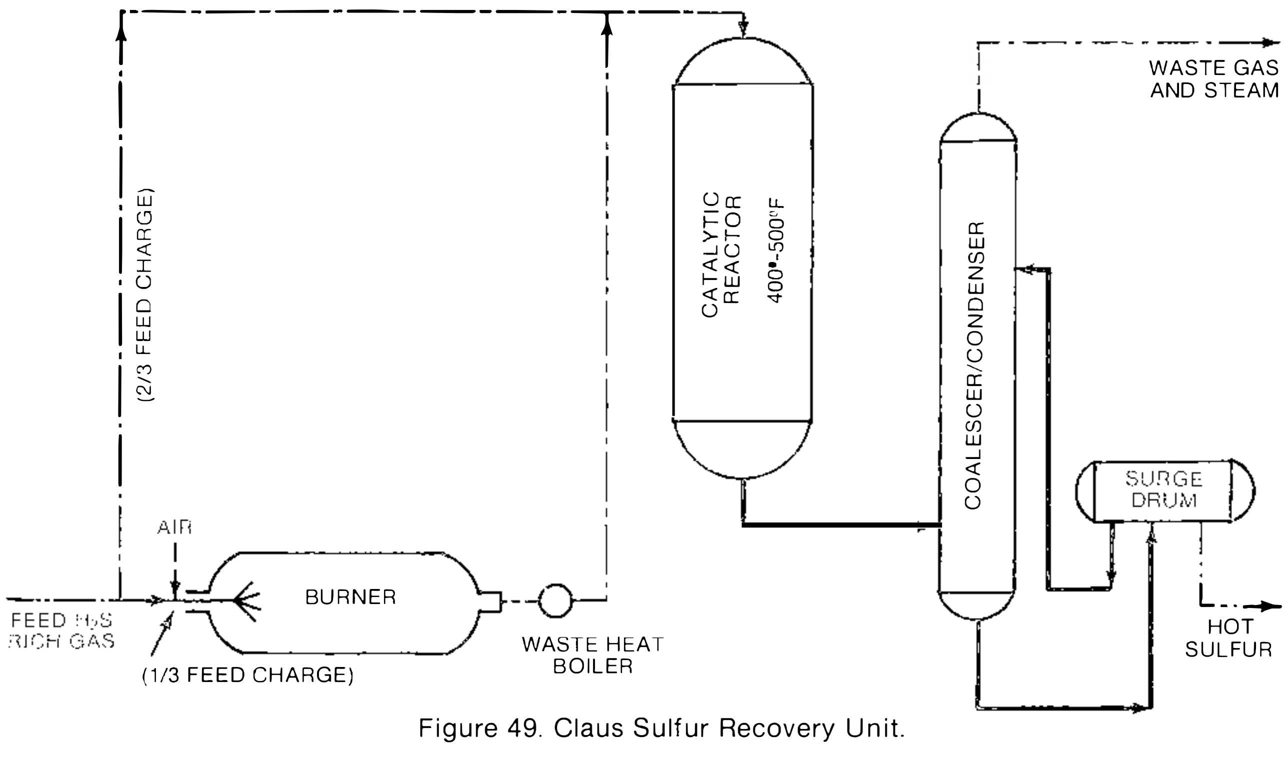


Figure 49. Claus Sulfur Recovery Unit.

NOTE: The legend appears on Figure 27.

feed is burned to SO_2 at about 1,800°F in a sulfur boiler that recovers 80 percent of the overall heat of reactions by generating steam. The resulting mixture of four parts H_2S to two parts SO_2 forms sulfur by the Claus reaction:

$$6H_2S + 3O_2 \longrightarrow 2SO_2 + 2H_2O + 4H_2S$$

$$4H_2S + 2SO_2 \longrightarrow 6S + 4H_2O$$

The reaction is carried to completion in a series of catalytic converters with beds of bauxite or alumina at 400 to 500°F. Sulfur is condensed and removed after the boiler and each converter. With a concentrated feed, overall conversion is about 92 percent with two catalytic stages, 92 to 95 percent with three stages, and 96 to 97 percent with four stages. The majority of the remaining sulfur is removed by the tail gas treating plant.

3. Claus Tail Gas Treatment

The compositions of typical Claus tail gases fall in the ranges shown in Table 36. If all these sulfur compounds are converted to SO_2 by incineration, the tail gas will contain up to 15,000 parts per million (ppm) of SO_2. If this quality is not acceptable, a number of proprietary processes have been developed to limit the sulfur content of Claus tail gases to acceptable levels. It is characteristic of these processes that the capital and operating costs vary inversely with the allowable sulfur content of tail gas discharged to the air. To achieve SO_2 concentrations below 500 ppm, the capital cost is at least as great as that of the sulfur plant to which it is attached. Further, the operating costs of all the processes greatly exceed the value of the sulfur recovered.

TABLE 36

Typical Range of Composition of Claus Plant Tail Gas

Component	Composition Range (ppm) (Dry Basis)
Hydrogen Sulfide	5,000 to 12,000
Sulfur Dioxide	2,500 to 6,000
Carbon Disulfide	300 to 5,000
Carbonyl Sulfide	300 to 5,000
Sulfur (Vapor)	100 to 200

SOURCE: American Petroleum Institute, "Atmospheric Emissions," Manual on Disposal of Refinery Wastes, 1977.

Numerous processes are available to treat tail gas from the Claus sulfur recovery unit. They are divided into reduction and oxidation processes. Both types have been used successfully in refinery operations; the choice depends upon the tail gas composition and process economics. Reduction processes convert sulfur compounds to H_2S. During the oxidation process, the sulfur recovery tail gas is incinerated to convert all sulfur compounds to SO_2. The hot flue gases are then sent to an absorber where the SO_2 is absorbed with a solution of sodium sulfite. The clean gas contains very slight concentrations of sulfur compounds and can be released to the atmosphere. The Beavon-Stretford (Figure 50) and the SCOT (Figure 51) processes are examples of the reduction process, and the Wellman-Lord (Figure 52) process is an example of the oxidation process:

- The Beavon-Stretford process employs a reactor containing cobalt molybdate to convert the sulfur compounds in the Claus tail gas to H_2S. Sulfur, SO_2, and mercaptans are hydrogenated by hydrogen in the feed, which is supplied by the water/gas reaction with feed CO. Carbon disulfide (CS_2) and carbonyl sulfide (COS) are hydrolyzed by water in the feed to residuals of about 25 ppm each. The reactions involved are:

$$S + H_2 \longrightarrow H_2S$$

$$SO_2 + 3H_2 \longrightarrow H_2S + 2H_2O$$

$$CH_3SH + H_2 \longrightarrow H_2S + CH_4$$

$$CO + H_2O \longrightarrow H_2 + CO_2$$

$$CS_2 + 2H_2O \rightleftharpoons 2H_2S + CO_2$$

$$COS + H_2O \rightleftharpoons H_2S + CO_2$$

  The Beavon-Stretford process yields a tail gas containing less than 200 ppm of sulfur compounds after incineration. It is not sensitive to CO_2 in the feed (see Figure 50).

- In the SCOT process the tail gas is reduced to H_2S by hydrogenation over a cobalt/molybdenum catalyst at about 570°F. The H_2S is cooled, absorbed in an alkanolamine solution, usually mono- or di-ethanolamine or di-isopropanolamine, which is regenerated by reboiling. The H_2S released is returned to the Claus unit feed.

  Typically the absorber tail gas contains 200 to 500 ppm of H_2S and it is incinerated before release. As the absorbing solution will coabsorb 20 to 30 percent of the CO_2 in the Claus tail gas, a buildup of CO_2 can occur if the initial concentration exceeds 20 percent (see Figure 51).

- In the Wellman-Lord process the tail gas is incinerated and the SO_2 absorbed in sodium sulfite (Na_2SO_3) to form

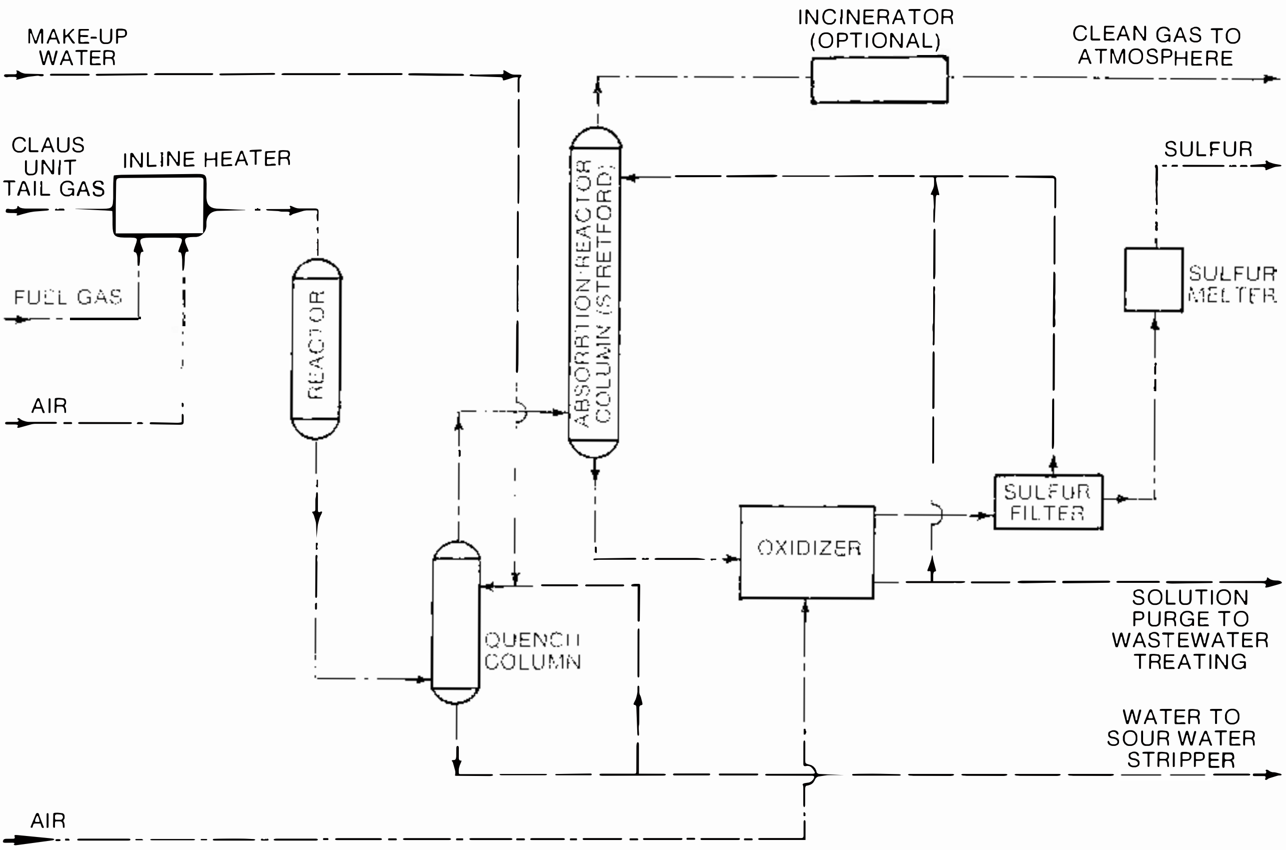


Figure 50. Beavon-Stretford Tail Gas Treating Unit.

NOTE: The legend appears on Figure 27.

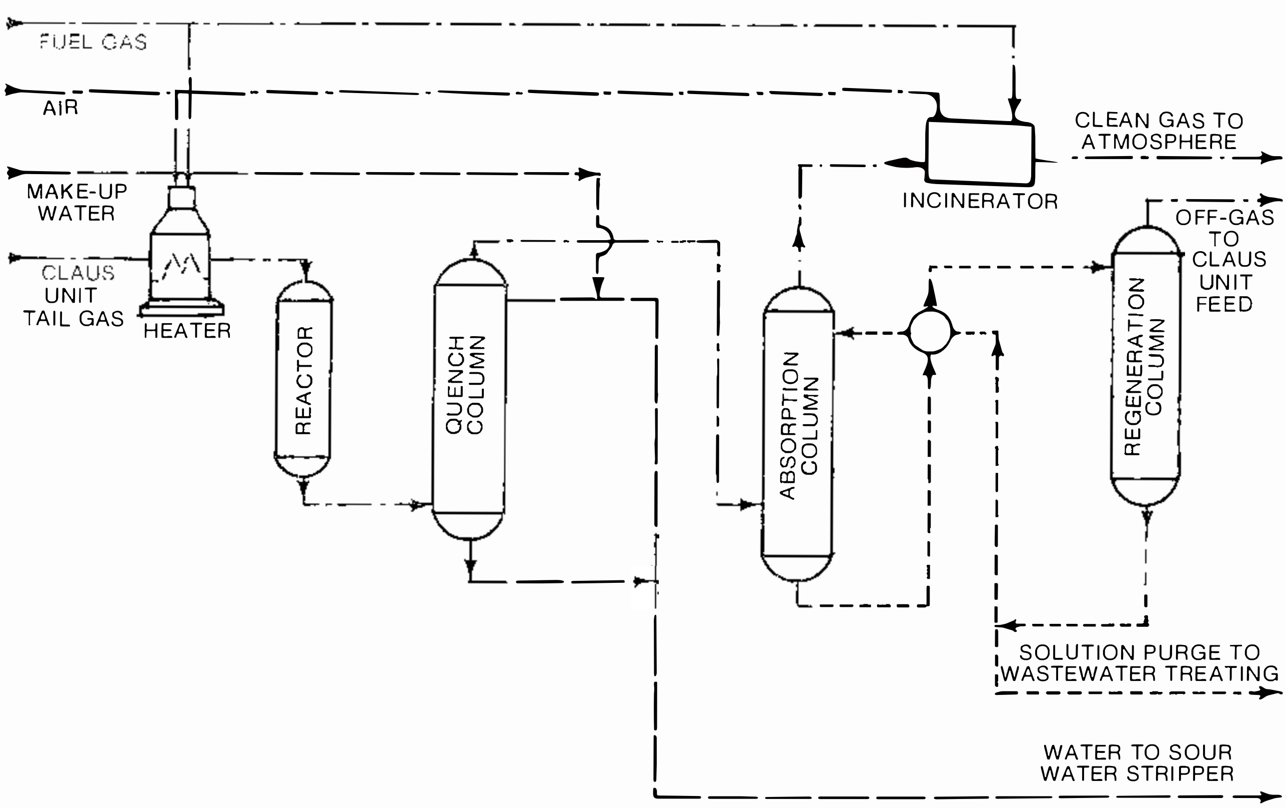


Figure 51. SCOT Tail Gas Treating Unit.

NOTE: The legend appears on Figure 27.

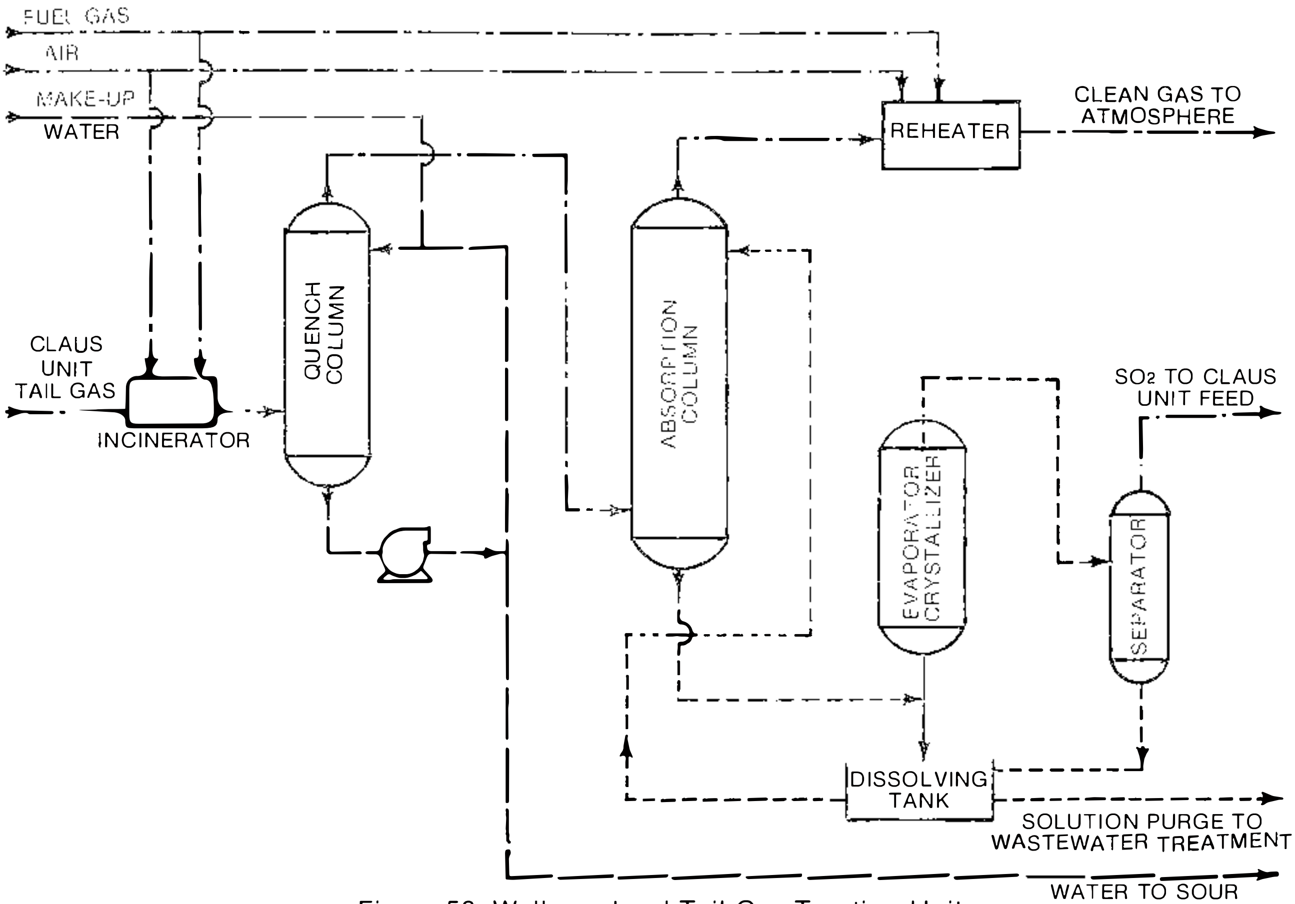


Figure 52. Wellman-Lord Tail Gas Treating Unit.

NOTE: The legend appears on Figure 27.

sodium hydrosulfite ($2NaHSO_3$). The absorbing solution is regenerated in an evaporator-crystallizer, which returns the freed SO_2 to the Claus plant. The reactions are:

$$Na_2SO_3 + SO_2 + H_2O \longrightarrow 2NaHSO_3$$

$$2NaHSO_3 \xrightarrow{\text{Heat}} Na_2SO_3 + SO_2 + H_2O$$

$$2Na_2SO_3 + SO_3 \longrightarrow Na_2SO_4 + Na_2S_2O_5$$

$$Na_2S_2O_5 + 1/2\ O_2 \longrightarrow Na_2SO_4 + SO_2$$

A purge stream is required to control the concentration of sodium sulfate. This process can yield a tail gas containing less than 200 ppm of SO_2. It is not sensitive to CO_2 (see Figure 52).

C. Sources of NO_x

As refinery contributions of chemical NO_x are negligible, further discussion will be confined to NO_x from combustion. Exhaust and flue gases from combustion usually are colorless and composed mainly of nitrous oxide (NO) at concentrations below 0.1

percent. Two types of NO_x produced by combustion are discussed below.

Thermal NO_x is produced by the fixation of atmospheric nitrogen in the flame according to the reaction:

$$N_2 + O_2 \rightleftharpoons 2NO$$

This reaction proceeds to a level of NO that depends upon variables such as the temperature, pressure, concentrations, and rates of gas flow through different zones within the flame. Kinetic studies of the combustion process indicate that oxygen atoms and nitrogen atoms are formed as an essential part of chain reactions involved:

$$O + N_2 \rightleftharpoons NO + N$$

$$N + O_2 \rightleftharpoons NO + O$$

Overall, the main factors in thermal NO and NO_2 formation derived from it are flame temperature, the length of time the combustion gases are maintained at high temperature, combustion pressure, and the amount of excess oxygen present. Therefore, in the combustion of natural gas, which is virtually free of bound nitrogen, the quantities of NO_x produced in the absence of special controls may exceed 1,000 ppm in flue gases from large electric utility boilers. This fact indicates clearly that high temperature fixation of atmospheric nitrogen occurs.

Fuel NO_x is due to the oxidation of a portion of the nitrogen combined in the fuel. This chemically bound nitrogen reacts with oxygen much more readily than the molecular nitrogen supplied with the combustion air. However, the bound nitrogen goes mainly to molecular nitrogen and only partly to NO_x emissions. NO_x is formed at a higher rate via the oxidation of fuel nitrogen than through the reaction of oxygen with molecular nitrogen. The role of fuel nitrogen content has been studied in laboratory fuel oil combustion experiments, which indicate that NO_x formed by the oxidation of fuel nitrogen is relatively unaffected by changes in combustion conditions.

Both thermal and fuel NO_x may be produced in refineries. The major sources are shown in Table 37.

D. Control of NO_x Emissions

1. NO_x Emission Factors

Emission factors can be of value in assessing the problems of controlling NO_x. They must be used with caution, however, because of the following variables encountered:

- The type of fuel used in combustion has a bearing both on the production of NO_x and on the ease of controlling it.
- Combustion units operating under relatively mild conditions give an exhaust gas containing only small amounts of NO_x

TABLE 37

Refinery Sources of NO_x from Combustion

Classification	Source	Thermal NO_x	Fuel NO_x
High Temperature	Power Boilers Firing -- Gas	Present	Possible
	Power Boilers Firing -- Oil	Present	Present
	Power Boilers Firing -- Coal	Present	Strong
Internal Combustion	Engines	Present	Unlikely
	Turbines	Strong	Possible
Moderate Temperature	Carbon Monoxide Boilers	Present	Present
	Coke and Residual Fuels	Present	Present
	Catalyst Regeneration	Unlikely	Present
	Incineration	Present	Present
	Process Heating -- Gas Cracking	Present	Possible
	Oil Cracking	Unlikely	Possible
	Oil Heating	Unlikely	Possible

SOURCE: American Petroleum Institute, "Atmospheric Emissions," Manual on Disposal of Refinery Wastes, 1977.

(such as 10 ppm or less formed in a typical domestic gas-fired water heater). This range rises rapidly with combustion temperature due to thermal NO_x and may reach 1,500 ppm or more.

- There is also much uncertainty in the literature as to the reliability of measurements of NO_x made by different methods over a period of years.

Petroleum refining is a minor factor in the industry combustion segment, amounting to an estimated 1.5 percent of NO_x emissions from stationary sources (see Figure 47).

2. Control Methods

The problems of controlling NO_x emissions from combustion sources are much more complex than those encountered with SO_x. Due to the fixation of atmospheric nitrogen as thermal NO_x, even the complete removal of nitrogen from the fuel will not result in

a flue gas free from NO_x. Therefore, it may be necessary to use combinations of the following three basic processes, which are available to control NO_x from combustion:

- Use of a fuel of low nitrogen content to reduce formation of fuel NO_x
- Adjustment of combustion conditions to minimize the production of thermal NO_x
- Treatment of the combustion products to remove NO_x.

The second method offers the most immediate promise of success at lower cost. High flame temperature and high excess air have been built into many industrial combustion processes to avoid contamination from smoke, carbon monoxide, and unburned hydrocarbons. Such processes operate at high thermal efficiency, but they also contribute to high thermal NO_x formation. Thus, combustion controls that move away from peak flame temperatures will lower thermal NO_x. The controls must be carefully engineered and well supervised, however, to avoid the other forms of air pollution. Control processes meeting these requirements have been developed for application to the following:

- Oil- and gas-fired boilers that respond to such modifications as low excess air and second stage combustion. (These boilers are designed to lower the effective flame temperature and limit available oxygen.)
- Reciprocating internal combustion engines and turbines, which respond to many of the methods developed to control automotive exhaust emissions.

Finally, a number of treatment processes are available to reduce the NO_x contents of exhausts and flue gases. At present, high costs limit their application.

E. Sources of Hydrocarbon Emissions

The potential sources of hydrocarbon emissions in a refinery include fixed roof storage tanks, loading operations, oil/water separators, relief valves, blowdown stacks, asphalt oxidizing pumps and compressors, vacuum distillation, vents, sewers, cooling towers, furnaces, and sampling.

F. Control of Hydrocarbon Emissions

1. Flares

Refinery flares are special burners used to destroy unavoidable emissions of hydrocarbon and other combustible gases. It is necessary to burn such gases in order to prevent deleterious effects on people, animals, and plants and to comply with federal, state, and municipal regulations.

The refinery flare must be capable of handling very arge releases of hydrocarbons that exceed the capacity of the system for control and recovery. Such releases can occur in emergencies resulting from the failure of equipment or from fires. A detailed discussion of flare operations is contained in the Industry Operations section of this chapter.

2. Storage Tanks

The emission control technology for storage tanks is described in Chapter Four.

3. Primary Gravity Separators

The primary gravity sedimentation device employed to separate oil from wastewater is normally an API separator. In the process of sedimentation, oil contained in the wastewater rises to the top of the separator and, if the area is uncovered, evaporation occurs and hydrocarbon vapors are emitted.

There are two basic methods of emission control. The first involves design modifications to and suitable maintenance of the wastewater collection system upstream of the separator to reduce the total amount of oil. The second method involves covering the separator, utilizing either a fixed or a floating cover.

4. Leakage

The principal control of equipment leakage from valves, flanges, vessel drains, and pump drips is a periodic inspection and maintenance program.

5. Furnaces

A considerable series of tests in the field indicated that burner emissions were insignificant and were all in concentrations less than 100 ppm, including samples taken from the first few seconds of operation. Under more normal burning conditions the concentration of hydrocarbons, aldehydes, and organic acids in the gaseous emissions products does not usually exceed 20 ppm when burning No. 6 fuel oil. Usually these emissions cannot be measured by quantitative techniques now available.

Because hydrocarbon emissions from this source are so low (in most cases below the range of available quantitative measuring techniques) the only method of control is good maintenance of the burners.

6. Cooling Towers

If the cooling water is oil contaminated, no practical method of hydrocarbon emission control is available. Therefore, efforts are directed to inspection and detection of leaks and maintenance as and if required.

7. Pressure Relief Valves

Pressure relief systems are required to protect refinery process equipment against excessive pressures caused by fires, accidents, and process upsets. They consist of pressure relief valves for liquids and safety valves for gases. These valves may be spring loaded, pilot operated, or weight loaded, but all are designed to open at a pressure set to protect the vessel and to close when relief is obtained. Control of these emissions may be obtained by minimizing leakage or by using closed relief systems.

8. Vacuum Distillation

Heavy oils boiling at temperatures up to about 1,050°F are distilled from crude oil residues under reduced pressure in vacuum towers. The very low pressure is maintained by steam-actuated vacuum jets followed by surface condensers.

Some cracking occurs during distillation, producing noncondensable decomposition products. Emission rates depend upon the feedstock and operating conditions. As they often have very foul odors, these gases are usually burned in one of the unit furnaces.

9. Catalyst Regeneration

Fixed beds of catalysts are employed in catalytic reforming, hydrocracking, and desulfurizing. In these processes, regeneration is relatively infrequent and the beds are purged of light hydrocarbons to a closed system before burning. Thus, emissions to the atmosphere usually are negligible.

Moving beds of catalysts are used in cracking by both the fluid catalytic cracking and Thermofor catalytic cracking processes. In both types, the spent catalyst is removed continuously from the reactor, burned in a separate regenerator, and returned to the reactor with the fresh feed. While the concentrations of unburned hydrocarbons in the waste gases are low, the quantities of waste gases are very large. CO waste heat boilers are commonly used to control hydrocarbon and CO emissions while recovering waste heat. Hot regeneration operation is also commonly used to control CO emissions.

10. Asphalt Oxidizing

In the production of high quality asphalts for applications such as roofing, the crude oil vacuum still asphaltic resid must be further refined to the desired consistency. This is accomplished by air blowing at elevated temperatures, usually 350 to 500°F, which removes any residual gas oil and polymerizes the asphalt. The resultant exhaust air contains hydrocarbons and aerosols. Emissions from air blowing may be reduced by vapor scrubbing, vapor incineration, or a combination of both.

11. Pumps and Compressors

The most common types of refinery pumps are centrifugal and reciprocating. Leakage losses occur on these pumps where the driving shaft passes through the pump casing. These emissions include nonvolatile as well as volatile products. In refinery applications, the pump shaft leakage is usually controlled with a packed seal or a mechanical seal.

Further reductions in emissions from pumps and compressors can be achieved by dual mechanical seals, secondary liquid seals, or a conventional vapor recovery system.

G. Sources of Odor Emissions

The products, by-products, and wastes from petroleum operations represent hundreds of organic compounds, many of which have some odor potential. Specific odorous compounds producing obnoxious odors include phenolic compounds, low-molecular-weight aldehydes and ketones, ammonia, and such sulfur compounds as H_2S, mercaptans, and organic sulfides and disulfides.

H. Control of Odor Emissions

The most successful and economic methods of controlling refinery odors are: eliminating them by modifications to the process or operating procedures, and avoiding accidental releases by providing good housekeeping and proper maintenance. Odors that cannot be eliminated by such means are treated by the following techniques:

- Incineration in either catalytic or direct-fired incinerators is the most effective means of disposing of odorous compounds with inoffensive combustion products.

- Adsorption on a solid adsorbent such as activated carbon provides recovery of the odorous compound and regeneration of the adsorbent. Final disposal may be by sale or incineration.

- Absorption in a liquid that either dissolves the odorous material or reacts with it to form a stable compound. Normally the absorbing liquid is regenerated, releasing the concentrated odorous compounds for disposal.

- Neutralization of acidic or alkaline gases can be effected by scrubbing with suitable liquids. However, disposal of the aqueous wastes can present problems.

- Chemical oxidation of odorous compounds can be achieved by such oxidizing materials as sodium hypochlorite or potassium permanganate.

I. Sources of Particulate Emissions

Particulate emissions from refinery operations are primarily limited to the off-gases from fluid catalytic cracking and fluid coking.

J. Control of Particulate Emissions

The principal refinery process unit subject to control of particulates is the fluid bed catalytic cracker. Particulates are controlled by an electrostatic precipitator, high efficiency cyclones, dry scrubbers, wet scrubbers, or baghouses. The most commonly used equipment is the electrostatic precipitator.

The electrostatic precipitator removes particulates from gas streams by passing the gas between a pair of electrodes -- a discharge electrode at a high potential and an electrically grounded collecting electrode. The potential difference must be great enough so that a corona discharge surrounds the discharge electrode. Under the action of the electrical field, gas ions formed in the corona move rapidly toward the collecting electrode and transfer their charge to the particles by collision with them. The electrical field interacting with the charge on the particles then causes them to migrate toward, and be deposited on, the collecting electrode.

The dust layer that forms on the collecting electrode is removed by intermittent rapping that causes the deposit to break loose from the electrode. In effect, this returns the dust to the gas stream but not in its original finely divided state. As a result of cohesive forces developed among the particles deposited on the electrode, the dust is returned as agglomerates, which are large enough for gravity to cause them to fall into dust hoppers below the electrodes. Reduced to its essentials, the electrostatic precipitator acts as a particle agglomerator combined with a gravity settling chamber.

The electrical mechanisms required for precipitation of particles are addition of an electrical charge to the particles, and application of an electrostatic force that causes the charged particles to migrate toward the collecting electrode. In the usual industrial electrostatic precipitators, both are supplied simultaneously, and the precipitator acts as a single-stage unit.

WATER

I. Standards and Regulations -- Clean Water Act

The general provisions of the Clean Water Act are discussed in Chapter One. The regulatory mechanism for establishing specific discharge limitations for individual dischargers is through promulgation of effluent guidelines. They serve as guidance for development of specific limitations to be incorporated in National Pollutant Discharge Elimination System (NPDES) permits issued to individual refineries. Other provisions of the Clean Water Act that can impact the refining industry are those relating to oil spills, water quality standards, a requirement to employ Best Management Practices (BMP) and, "...the national goal that the discharge of pollutants into the navigable waters to be eliminated by 1985...."

A December 1980 report by the Subcommittee on Oversight and Review of the House Committee on Public Works, entitled *Implementation of the Federal Water Pollution Control Act*, is a thorough review of progress under the Act as of that date. In particular, the problems and shortcomings relating to the Act's implementation, many of which impact the refining industry, are discussed.

A. NPDES Permits

With passage of the Federal Water Pollution Control Act Amendments of 1972, EPA established the NPDES permit program, which superseded the prior permit requirements administered by the U.S. Army Corps of Engineers under the authority of the Refuse Act of 1899. As a general rule, initial NPDES permits issued to individual refineries contained interim limitations pending development of Best Practicable Control Technology (BPT) and Best Available Technology (BAT) limitations as provided for in the Act. As of year-end 1981, refinery NPDES permits specified BPT limitations while BAT limitations were yet to be finalized. Being a major industry, refineries were among the first to be included in the NPDES program. In addition to specific limitations, such permits contain many other requirements, such as those for monitoring, record keeping, and reporting.

The many problems with the NPDES permit program are highlighted in the December 1980 report by the Subcommittee on Oversight and Review of the House Committee on Public Works.[9] The Subcommittee notes therein that the "...NPDES permit program is on the verge of collapse..." in that the program requirements have overwhelmed both the regulators and the regulated community.

B. Best Practicable Control Technology

The Clean Water Act specifies that BPT requirements be implemented by July 1, 1977. Effluent limitations contained in individual refinery NPDES permits are for the most part derived from effluent guidelines and standards for petroleum refining.[10,11]

To arrive at the effluent limitation guidelines, EPA assumed the installation of certain types of control technology, along with a long-term effluent concentration said to be achievable with such technology, and assigned a statistically derived wastewater flow volume to all refineries within a certain subcategory. Given these assumptions along with adjustment factors relating to refinery complexity and size, an allowable mass discharge for each individual refinery within the industry was calculated. For the most part, the industry finds no fault with the BPT treatment technology espoused or the achievable effluent concentrations assumed for that technology. However, the application of the statistically derived flow volumes to arrive at the final limitations has had, and in some instances continues to have, a serious impact on refineries with actual wastewater flow volumes significantly above those assumed. Another aspect of the permit limits derived from these effluent guidelines that has caused some difficulty and controversy

is the assigned variability factors used to derive 30-day average and one day maximum limitations from the long-term achievable effluent concentrations referred to earlier.

For purposes of establishing BPT limitations, EPA divided the refining industry into five subcategories. These subcategories and the statistically derived wastewater flow volumes assigned to each are listed in Table 38. The treatment technologies for BPT limitations included both in-plant and end-of-pipe technology.[12]

BPT in-plant technology was based on control practices widely used within the petroleum refining industry, and include the following:

- Installation of sour water strippers to reduce the sulfide and ammonia concentrations entering the treatment plant
- Elimination of once-through barometric condenser water by using surface condensers or recycle systems with oily water cooling towers
- Segregation of sewers, so that unpolluted storm runoff and once-through cooling waters are not treated with the process and other polluted waters
- Elimination of polluted once-through cooling water, by monitoring and repair of surface condensers or by use of wet and dry recycle systems.

BPT end-of-pipe treatment technology was based on the existing wastewater treatment processes currently used in the petroleum refining industry. These consisted of equalization and storm diversion; initial oil and solids removal (API separators or baffle

TABLE 38

Refining Industry Wastewater Flow Volume

Subcategory*	Wastewater Flow Volume (Gallons of Wastewater Per Barrel of Feedstock)
Topping	20
Cracking	25
Petrochemical	30
Lube Oil	45
Integrated	48

*For a further description of these subcategories see Table 16 of: U.S. Environmental Protection Agency, "Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Petroleum Refining Point Source Category," April 1974.

plate separators), further oil and solids removal (clarifiers, dissolved air flotation, or filters); carbonaceous waste removal (activated sludge, aerated lagoons, oxidation ponds, trickling filter, activated carbon, or combinations of these); and filters (sand, dual media, or multimedia) following biological treatment methods.

The long-term pollutant effluent concentrations said to be achievable with the above-described BPT technologies and the variability factor used to derive 30-day average daily and one-day maximum concentrations are listed in Table 39. With few exceptions, the refining industry successfully met the July 1, 1977, deadline for the installation of BPT technology. Further, it can

TABLE 39

Long-Term Achievable Effluent Concentrations by Refineries Using BPT Technology*

Parameter	Achievable Concentration (mg/l)	Variability Factor 30-Day Average	Variability Factor Daily Maximum
Biochemical Oxygen Demand (BOD)	15	1.7	3.2
Chemical Oxygen Demand (COD)	--	1.6	3.1
Total Organic Carbon (TOC)	33†	1.6	3.1
Total Suspended Solids (TSS)	10	2.1§	3.3§
Phenol	0.1	1.7	3.5
Oil and Grease (O&G)	5	1.6	3.0
Ammonia (NH_3 as N)	80% Removed	1.5	3.3
Sulfide	0.1	1.4	3.1
Total Chromium	0.25	1.7	2.9
Hexavalent Chromium	0.02§	1.4	3.1

*Source of Data: U.S. Environmental Protection Agency, "Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Petroleum Refining Point Source Category," April 1974.

†Based on TOC/BOD ratio of 2.2. Ratio is variable and should be correlated for each refinery.

§Achievable concentrations and variability factors changed in 40 FR 21939, Federal Register, May 20, 1975.

be stated that despite greater problems at individual refineries, compliance has been achieved with the BPT limitations throughout the industry. As will be discussed la er in this chapter, these efforts have resulted in a substantial reduction in the discharge of pollutants from the refining indust y.

C. Best Available Technology

The 1972 Federal Water Pollution Control Act Amendments specified that BAT be implemented by July 1, 1983. With the 1977 amendments to the Act this date was changed to July 1, 1984, and BAT was redefined to be primarily directed at the control of "toxic" pollutants. BAT is also required for the nonconventional pollutants [chemical oxygen demand (COD), ammonia sulfides, and total organic carbon (TOC)] but waivers may be available.[13]

EPA promulgated BAT requirements for the refining industry along with the BPT requirements in May 1974. These BAT requirements were based on the use of activated carbon treatment and were challenged by the American Petroleum Institute (API) and others in the Tenth Circuit Court of Appeals. The Court, in its decision of August 11, 1976, remanded the BAT requirements to EPA based on the fact that granular activated carbon treatment was not a proven treatment technology for refinery wastewaters.

New BAT requirements were proposed for the petroleum refining industry on December 21, 1979.[14] These proposed BAT requirements are of serious concern to the refining industry and extensive comments on the proposal have been submitted by API[15,16,17] and by individual refiners. Paramount among these concerns is the continued use by EPA of a statistically derived wastewater flow model. Further, the theoretical flow model is then coupled with a presumed achievable wastewater flow reduction, and the assumption is made that a reduction in wastewater flow will result in an equivalent reduction in the quantity of pollutants discharged. That portion of the refining industry that cannot reasonably achieve the presumed achievable flow model, let alone the additional presumed achievable flow reduction, stands to be seriously impacted despite the fact that they may already have an exceptionally high level of wastewater treatment in place.

As stated above, the 1977 amendments to the Clean Water Act redefined BAT to be primarily directed at the control of "toxic" pollutants. Specifically, Congress, in Section 307(a) of the 1977 amendments, declared 65 compounds and classes of compounds as toxic, hence requiring BAT level of control. These 65 compounds and classes of compounds were further broken down to 129 priority pollutants. In the December 21, 1979, Proposed Refinery Effluent Guidelines, EPA proposed BAT limitations for only two pollutants: total phenol [4-aminoantipyrine method (4-AAP)], and chromium (both total chromium and hexavalent chromium).[18]

It should be noted that the BAT requirements as of year-end 1981 had not been finalized and, apart rom the concerns expressed

above, it is not possible to comment meaningfully on what may yet be entirely different requirements. BAT requirements are due to be issued in May 1982.

D. Best Conventional Pollutant Control Technology

The 1977 amendments to the Clean Water Act, in keeping with the focus of BAT requirements on toxic pollutants, removed "conventional" pollutants from the BAT category and established a separate BCT category. In so doing, Congress specifically required that any new limitations on conventional pollutants be subjected to a "cost reasonableness" test, which involves a comparison of the cost and level of reduction of such pollutants from a class or category of industrial sources with that for publicly owned treatment works (POTW). Conventional pollutants were defined by Congress in the 1977 amendments as biochemical oxygen demand (BOD), total suspended solids (TSS), fecal coliform, pH, and any pollutants defined by the Administrator of EPA as "conventional." On July 30, 1978, the Administrator added oil and grease (O&G) to the list.[19]

In proposing BCT limitations in the December 21, 1979, proposed Refinery Effluent Guidelines, EPA again relied on the use of its statistically derived flow model and presumed achievable flow reduction concept discussed previously. The same comments and concerns expressed for BAT apply for Best Conventional Pollutant Control Technology (BCT). In commenting on the BCT proposal, API noted that EPA had improperly applied the cost-reasonableness test and that additional controls on conventional pollutants were not cost-effective. In July 1981, the U.S. Court of Appeals for the Fourth Circuit vacated all EPA regulations purporting to establish BCT effluent limitations under the Clean Water Act.[20] The Court held that the EPA's "cost reasonableness" test was insufficient, but the Court did not specify particular factors to be considered in such a test. EPA was directed to reconsider the "cost reasonableness" test. These requirements had not been made final by year-end 1981.

E. Water Quality Standards

The Federal Water Pollution Control Act provides that the Administrator of EPA shall approve water quality standards issued by a state if those standards are consistent with the requirements of the Act. In cases where states have issued no standards or inconsistent standards, EPA promulgates applicable standards. The Act further provides that where effluent limitations derived from either BPT or BAT do not result in attainment and maintenance of federal water quality standards, more stringent limitations will apply. In view of the severe impact such requirements could impose, it is extremely important that such water quality standards be based on sound scientific evidence and that such water quality standards be applied in a meaningful sense. On this latter point, it is important that regulating agencies take care not to impose very stringent water quality standards on small streams, which may consist mostly of treated refinery wastewater and which, in turn,

enter a much larger receiving stream where all applicable water quality standards may be met. Such an extreme application of this requirement, if attainable at all, could impose a very severe economic penalty on the affected refinery without any meaningful environmental benefit.

F. Elimination of Discharge of All Pollutants

The national goal of what is commonly referred to as "zero" discharge remains a part of the Act. It remains unclear just how this goal will be defined or whether or not such an objective, considered by many to be totally unrealistic, will survive scrutiny under any regulatory reform program. In considering such a concept, other negative environmental impacts and cost factors must be carefully considered.

In the December 21, 1979, Proposed Refinery Effluent Guidelines, EPA proposed a "zero" discharge for NSPS for new refineries. In so doing they noted that "EPA, however, solicits other data which would support or refute the assumption [emphasis added] that zero discharge is an achievable technology for new sources on a nationwide basis." API responded to this solicitation in its comments on the proposed refinery guidelines for the purpose of refuting what is considered to be a highly erroneous assumption.[21]

G. Spills

Section 311 of the Clean Water Act specifically deals with spills of oil and other hazardous substances.[22] Some of the regulations promulgated under Section 311 apply to marine transfer operations and accordingly would impact only those refineries with associated marine terminals.

As far as refineries themselves are concerned, the major thrust of these regulations is to require Spill Prevention, Control and Countermeasure and Oil Spill Contingency plans. Oil spills from refinery operations are not a major problem and are considered by the industry to be adequately controlled and regulated. For those refineries with marine terminal operations involving the transfer of crude oil or petroleum products to or from the refinery, there is obviously a greater risk of spillage and accordingly refineries apply more stringent control measures. All in all, the record for such operations has been good considering the tremendous volumes involved.

The quantities of hazardous substances used in refining are small compared to the volumes of oil handled. Materials used that are on the hazardous substance list are few and are used as treatment chemicals, lube process solvents, and additives. They include ammonia, benzene, chlorine, furfural, phenol, sodium hydroxide, sulfuric acid, hydrofluoric acid, tetraethyl lead, and toluene. These materials are handled with care; when spills do occur they are typically contained within tank dikes or removed during wastewater treating operations so that actual harmful releases to navigable waters are minimal.

H. Best Management Practices

The 1977 amendments to the Clean Water Act authorized EPA to prescribe BMP. EPA has published a BMP guidance manual and is writing BMP into new NPDES permits on a "best engineering judgment" basis. EPA is trying to define "best engineering judgment" for each industry in one pilot permit for each industry.

II. Impacts of Refinery Discharges on the Environment

A. Progress Made Through 1980

Substantial progress has been realized in the reduction of pollutant discharges throughout the refining industry. This is especially true in the 1970-1980 decade, largely due to the impetus of the Federal Water Pollution Control Act of 1972 and subsequent 1977 and 1978 amendments. Prior to 1972, differing regulatory requirements were imposed on individual refineries by state or regional government agencies. These requirements varied widely geographically and were largely dependent on the nature of the receiving stream and on whether such streams had water quality standards necessitating certain levels of treatment. Apart from meeting regulatory requirements, the degree of treatment prior to 1972 depended in large measure on the nature of the refinery, its relative age, and the policy of the refinery management.

As there have always been different levels of treatment at various refineries at any given time, it is difficult to relate results precisely and directly from one point in time to another. There are data available, however, that allow approximation of the degree of progress made in the refining industry. These data are discussed below.

1. Comparison of Discharge Levels

A 1968 API survey of refining industry discharges for 1967 presents data for 132 refineries representing approximately 87 percent of domestic crude oil processing capability in 1967.[23] These data can be compared with 1977 levels, calculated to result from the application of BPT technology.[24] The actual discharge levels reported to EPA for calendar year 1979 and the levels calculated to result from the application of proposed BCT technology for the 165 direct discharge refineries are intended to give a reasonable approximation of the progress in the reduction in pollutant discharges for the refining industry. These values are presented in Table 40 and are depicted in Figure 53.

The 165 direct discharge refineries mentioned above represented 14,142 MB/D, or 81 percent of U.S. refining capacity in 1976. Direct discharge refineries treat and discharge their own wastewater to navigable waters of the United States. Indirect dischargers discharge their wastewater to publicly or privately owned treatment plants. In 1976 there were 47 indirect dischargers, representing 2,402 MB/D, or 14 percent of U.S. refining capacity. The third

TABLE 40

Refinery Effluent Discharges, Direct Dischargers

Pollutant	1967*	BPT† July 1977	1979 Actual§	Proposed BCT July 1984¶	Percentage Reduction, 1967-1979
	[Thousands of Pounds Per Day (Annual Average)]				
Biochemical Oxygen Demand (BOD)	800	71	38	28	95
Total Suspended Solids (TSS)	500	47	43	18	91
Oil and Grease (O&G)	360	24	13	9	96

*Crossley, S-D Surveys, Inc., "1967 Domestic Refinery Effluent Profile," report prepared for the American Petroleum Institute, September 1968.

†American Petroleum Institute, "Comments of the American Petroleum Institute Regarding the Environmental Protection Agency's Proposed Effluent Limitations Guidelines, Pretreatment Standards and New Source Performance Standards for the Petroleum Refining Point Source Category." O&G by ratio to BOD.

§Calculated using EPA variability survey data; Personal correspondence, July 12, 1981, Jitu Shaveri (ERT) to J. M. Rieker (Mobil), "Summary of 1979 Average Mass Discharges for BCT Parameters for Refineries Selected by EPA for Variability Analysis," and American Petroleum Institute, "Evaluation of Cost-Reasonableness of Best Conventional Technology Regulations for the Petroleum Refining Point Source Category," June 1980.

¶U.S. Environmental Protection Agency, "Petroleum Refining Point Source Category Effluent Limitations Guidelines, Pretreatment Standards," 44 FR 75926, December 21, 1979.

category of refinery, zero dischargers, do not discharge wastewater to navigable waters of the United States. In 1976 there were 50 zero-discharge refineries representing 5 percent of U.S. refining capacity.[25]

The refining industry as a whole has achieved a better than 91 percent reduction of conventional water pollutants during the 1967-1979 period. Refinery process unit modernizations accounted for some of this improvement, but refineries made significant gains in the development of wastewater purificat on technology and waste management programs and the subsequent utilization of these developments in operations. Specifically, s gnificant reductions in

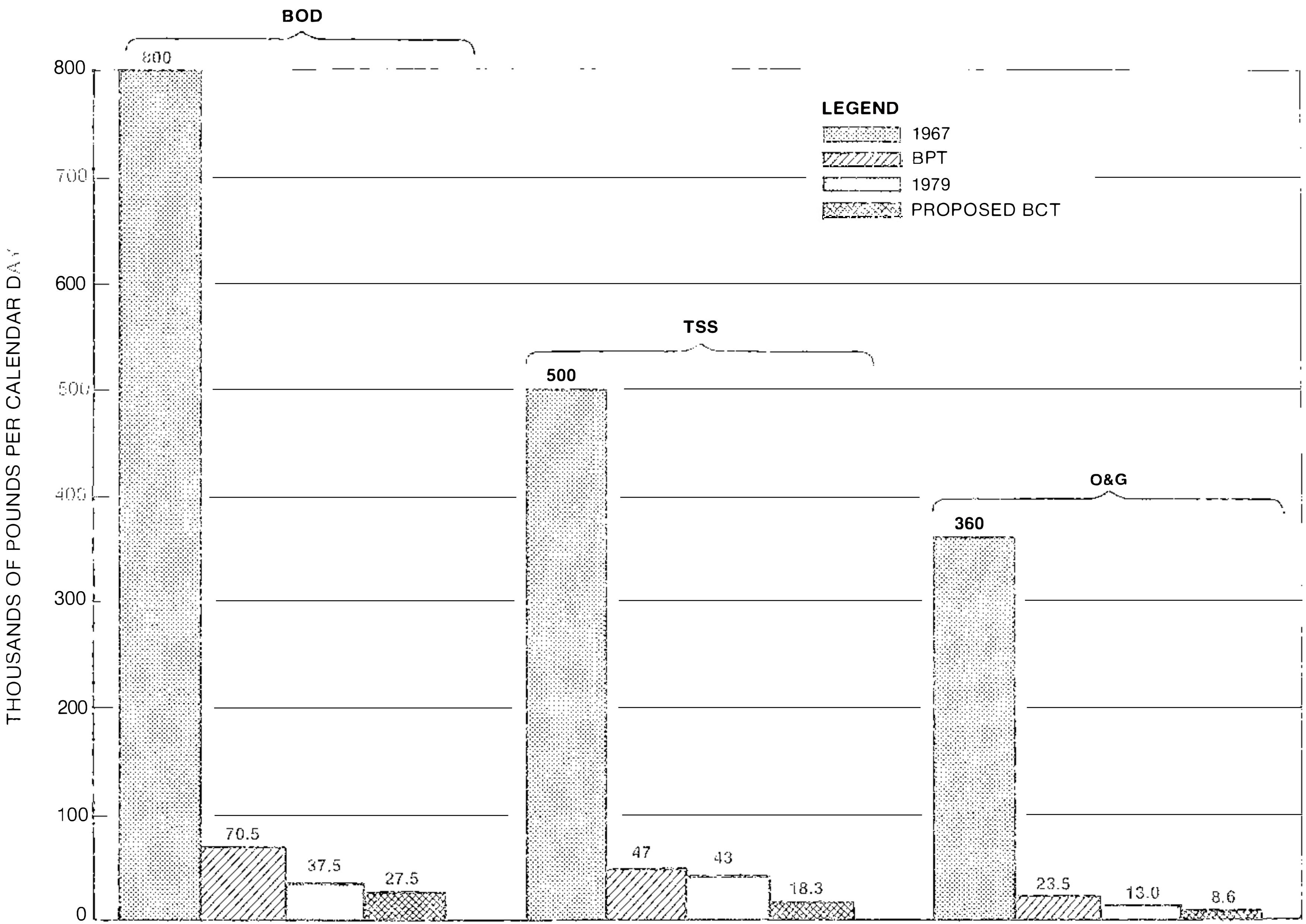


Figure 53. Comparison of Discharge Levels for Conventional Pollutants in the Petroleum Refining Industry.

SOURCE: 1967 data—American Petroleum Institute; BPT data—American Petroleum Institute; 1979 data—Environmental Protection Agency; BCT data—American Petroleum Institute and Environmental Protection Agency.

wastewater flow volumes per barrel of crude oil run have been achieved, and the state-of-the-art of the following technology areas was significantly advanced: sour water stripping; dissolved air flotation; granular media filtration; numerous biological wastewater purification processes; and water re-use practices.

The proposed BCT for 1984 will offer only marginal improvements over present discharge levels, yet would be costly to achieve. A means for estimating the cost-effectiveness of proposed BCT regulations is the "cost reasonableness" test, in which the cost (in dollars per pound) of removing the additional increment of conventional pollutants is compared for POTW and refineries.

In applying the "cost reasonableness" test, an API study determined that incremental pounds of TSS and BOD removed after BPT treatment would cost $5.39 per pound for refineries and $0.53 per pound for POTW. These data indicate that further reductions by refineries are marginal and costly, and that the BCT limitations should stay at present BPT levels.[26] Comparable data are not available for the nonconventional pollutants. The existing discharge levels for the industry as a whole are meeting appropriate limitations.

With respect to the refining discharge levels of the priority (toxic) pollutants, "EPA found that BPT treatment substantially reduces toxic pollutant concentrations. Most toxic pollutants are reduced to near or below the concentrations considered accurate for use in the Analytical Protocol developed by the Agency."[27]

In the December 21, 1979, proposed guidelines, EPA listed total chromium, hexavalent chromium, and phenols (4-AAP) as "toxic" pollutants requiring BAT level of control.[28] It is believed that existing levels of control within the refining industry constitute BAT for these substances.

It can be safely stated that the effectiveness of existing wastewater treatment practices in the refining industry equals or surpasses that of any other major industrial point source category. Further, that, based on available data, the effectiveness of refinery treatment substantially surpasses that of POTW.[29]

III. Wastewater Sources

A. Cooling Water

Cooling water is used in large volumes in petroleum refining operations. Cooling water usage can be divided into three categories: once-through noncontact cooling water; recycled cooling water circulated through cooling towers or ponds; and cooling water that has the potential to become contaminated or that contacts other contaminated wastewaters. An example of this latter category would be cooling water used on pumps, which most commonly enters the same sewer system that would receive minor leaks and spills from such operating equipment. Once-through noncontact cooling water is segregated from other wastewater streams because of the

large volumes employed and the relatively low risk of contamination. Existing regulations require the monitoring of TOC to assure the absence of significant leaks into the system.

For those refineries employing recycled cooling systems, blowdown from these systems represents a sizable portion of the combined wastewater flow. In general, blowdown quality will be similar to the feed water supply for a once-through cooling system except for the addition of corrosion control chemicals and concentrated dissolved solids present in the intake water. Systems that recirculate water concentrate total dissolved solid constituents because intake water is continuously evaporated to the surrounding environment. Cooling tower additives, total dissolved solid constituents, and contaminants entering the water through heat exchanger leaks constitute the pollution characteristics of cooling tower blowdown. The most commonly used additives for corrosion and algae control are chromates and phosphates.

Cooling water not segregated, such as that used for pump cooling, can be a significant source of the total wastewater volumes to the refinery process wastewater sewer system. For those refineries employing salt or brackish water as the source of such cooling water, the resultant introduction of high chlorides to the refinery wastewater treatment system precludes re-use of treatment plant effluent water for process water make-up.

B. Process Wastewater

There are some 175 process operations that have been identified in the refining industry. Virtually all of these processes have some potential to generate wastewater requiring treatment. Of these processes the following are particularly significant from a wastewater standpoint.

1. Crude Oil Distillation Processes

The wastewaters associated with crude oil desalting contain emulsified and free oils, ammonia, phenol, sulfides, and suspended solids. This wastewater stream is relatively high in BOD and COD, and contains significant levels of chlorides and other dissolved materials, which contribute to the overall dissolved solids concentration in the combined wastewater. Desalter effluent water normally exceeds 200°F and is commonly passed through heat exchangers, and sometimes is steam stripped prior to discharge to the refinery wastewater treatment plant.

The sources of wastewater from crude oil fractionation are generally from overhead accumulators, the wastewater discharge from oil sample lines, and the wastewater associated with the vacuum producing systems. The wastewater from the accumulators is a major source of sulfides, especially when sour crude oils are processed and the wastewater contains significant amounts of oil, chlorides, mercaptans, and phenols. The wastewaters from vacuum producing systems, which are used to create the reduced pressure in vacuum distillation units, are a source of emulsifiers that produce stable oil emulsions in the wastewater system.

2. Cracking and Coking Processes

Specific processes included in this category that are significant from a wastewater source standpoint are the following: visbreaking, thermal cracking, fluid catalytic cracking, moving bed catalytic cracking, hydrocracking, delayed coking, and fluid coking.

Catalytic cracking units are one of the largest sources of sour water in a petroleum refinery. Wastewaters from catalytic cracking are generally derived from the steam strippers and overhead accumulators on fractionators used to recover and separate various hydrocarbon fractions. The major pollutants resulting from catalytic cracking operations are oil, sulfides, phenols, and ammonia. These wastewaters are alkaline with high BOD and COD concentrations. Likewise, the major source of wastewater from thermal cracking (including coking) is the overhead accumulators on fractionators. These wastewaters also contain various oil fractions and may be high in BOD, COD, ammonia, phenol, and sulfides.

Wastewaters from hydrocracking, while normally low in volume, can be extremely high in sulfides and ammonia. The waste streams are generated in product separators and fractionation units following the hydrocracker reactors.

3. Hydrodesulfurizing Processes

These processes are used to remove sulfur, nitrogen, oxygen compounds, and other contaminants from either straight-run or cracked petroleum fractions. Hydrodesulfurizing also results in the saturation of olefins in the hydrogenation process. The quality and quantity of wastewater generated by the hydrodesulfurizing process depends on the type of process used and the material being hydrodesulfurized. The major wastewater streams come from overhead accumulators on fractionators, with the major pollutants being sulfides and ammonia. Phenolics also may be present.

As the petroleum refining industry moves toward the processing of heavier and higher sulfur crude oils, which are becoming an increasingly higher percentage of the types of crude oils available in the world marketplace, it can be expected that both the wastewater volumes and contaminant loadings will increase significantly due to increased utilization of the cracking and hydrotreating processes described above, which are necessary to process such crude oils. Accordingly, it is extremely important that any regulatory scheme consider this trend.

4. Lubricating Oil Processes

Four of the processes in this category that generate process wastewater are lube hydrofining, SO_2 ex raction, wax pressing, and phenol extraction. Wastewater from these operations includes acid-bearing rinse water and other wastewater streams usually high in dissolved and suspended solids, sulfates, sulfonates, and stable oil emulsions.

5. Reforming and Alkylation Processes

Catalytic reforming and sulfuric acid alkylation are two processes being used more extensively in the refining industry to replace "octanes" lost by the phaseout of lead additives in finished gasolines.

Reforming, which is a relatively clean process, will generate a small volume of wastewater. This wastewater stream is alkaline and the major pollutant is sulfide, which is derived from the overhead accumulator on the stripping tower used to remove light hydrocarbon fractions from the reactor effluent. In addition to sulfides, the wastewater contains small amounts of ammonia, mercaptans, and oil.

The general sources of wastewater in sulfuric acid alkylation units are the overhead accumulators in the fractionation section, the alkylation reactor, and the caustic wash. The wastewater from the overhead accumulators contains varying amounts of oil, sulfides, and other contaminants. The waste from the reactor consists of spent acid, which has a pH of less than 3. This stream is reprocessed to recover clean acid and, except for minor spills, does not enter the refinery sewer system. The major contaminants entering the sewer from a sulfuric alkylation unit are generally spent caustics from the neutralization of the hydrocarbon stream leaving the alkylation reactor.

C. Contaminated Storm Water

Storm water runoff is a high-volume, intermittent wastewater stream, which is both quantitatively and qualitatively unpredictable. The flow rate and contaminant concentration will not only vary with time during the course of a storm, but also will change with each individual area within a refinery. Large areas within a refinery, such as tank farms surrounded by dikes, afford the opportunity to retain substantial quantities of storm water for later discharge to the wastewater treatment plant, thereby minimizing surges to the system.

Storm water runoff, though usually relatively low in contamination, can be similar to the wastewaters generated during operation of the petroleum refinery, and there can exist in it BOD, COD, TSS, and O&G concentrations high enough to require treatment before discharge to a receiving stream

D. Ballast Water

Refineries that ship product by waterborne transport often have shore reception facilities to receive ballast from such vessels. Depending upon the nature of the terminal operation, the size of the vessels involved, and practical limitations to the size of receiving tanks onshore, relatively large volumes of waste ballast water (usually seawater) can require high rates of treatment over relatively short, intermittent periods. Some refineries direct waste ballast water to their main refinery wastewater treatment

plant, while others provide for separate physical/chemical treatment, particularly if the pier area is remote from the refinery proper.

E. Sanitary Wastes

Sanitary wastes are a relatively small portion of the total refinery wastewater load. Depending upon the refinery location and availability of sewage collection systems served by POTW, refineries may either collect and treat their own sanitary wastes or direct them to such POTW. When treated at the refinery proper, sanitary wastes normally receive secondary treatment and disinfection either separately or in combination with other refinery wastewaters.

F. Tank Draining

Tank draining is a significant intermittent source of wastewater that can have relatively high contaminant loadings. In particular, water bottoms from crude oil storage can substantially impact downstream treatment facilities.

IV. Wastewater Collection, Segregation, and Treatment

The quantities of wastewater requiring differing levels or types of treatment are a major factor in the cost and effectiveness of any treatment system. For this reason it is very important to segregate concentrated waste streams requiring extensive treatment from those usually larger volume, low-level contamination streams. In the case of certain wastewater streams, segregation is provided to permit separate in-plant treatment or pre-treatment prior to discharge to the main refinery treatment system.

Virtually all refineries have multiple collection and sewer systems. While each refinery differs, an example of the concept of segregation, along with treatment technologies sometimes employed, is shown in Figure 54. A number of wastewater treatment steps are discussed below.

A. Disinfection

Sanitary wastewater treated at the refinery normally requires some form of disinfection prior to discharge. Since the volume of sanitary wastes is usually small in relation to other refinery wastewaters, small package chlorinators can sometimes be used prior to secondary treatment without disturbing biological systems. In other instances it is necessary or more practical to disinfect the effluent from the secondary or tertiary treatment systems.

B. Sour Water Stripping

Sour or acid waters are produced in a refinery when steam is used as a stripping medium in various cracking processes or when water otherwise comes in contact with sour process streams (see

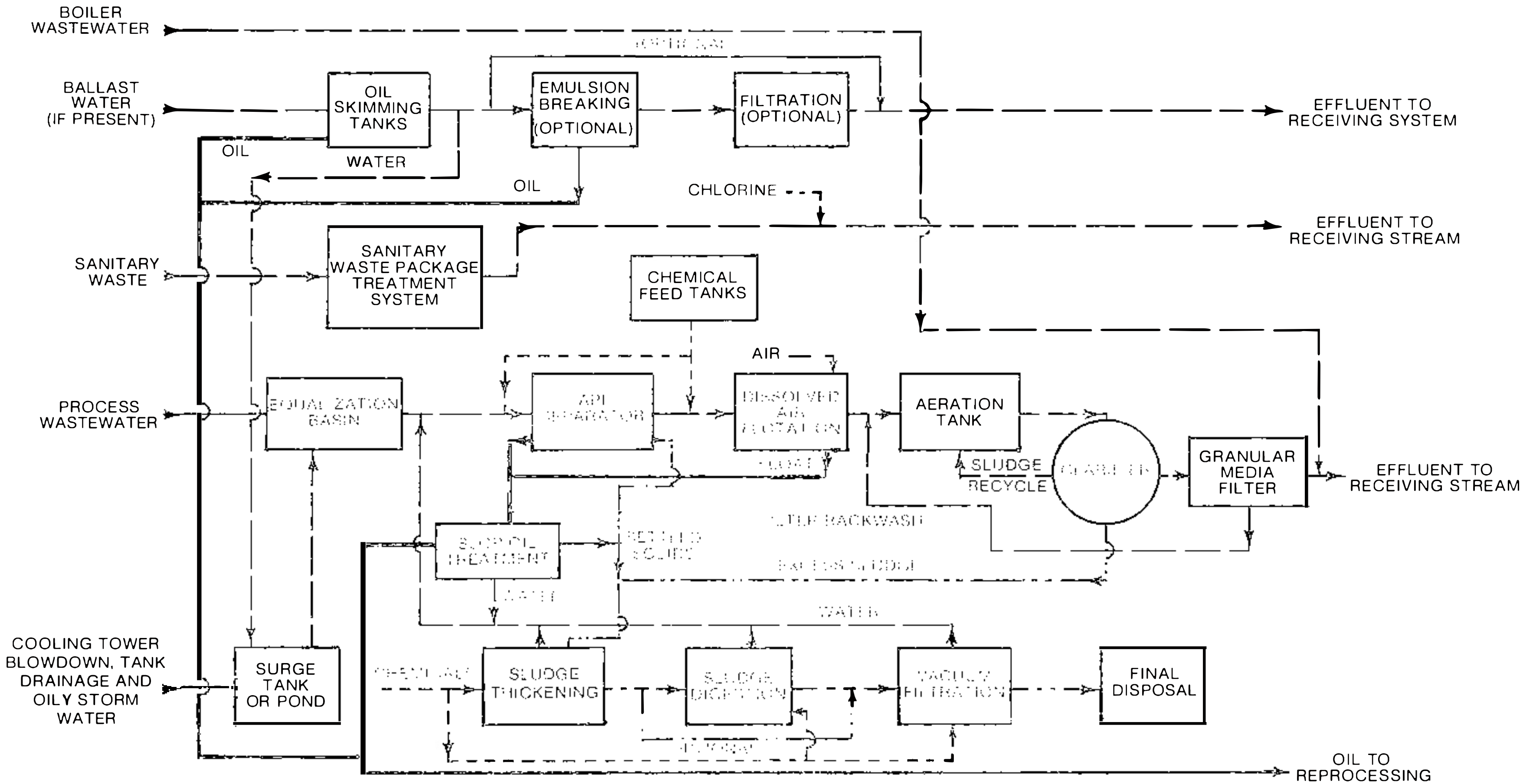


Figure 54. Wastewater Treatment Complex.

NOTE: The legend appears on Figure 27.

Figure 43). The H_2S, ammonia, and phenols distribute themselves between the water and hydrocarbon phases in the condensate. The concentration of these pollutants in the sour water varies widely, depending upon crude oil types and processing involved. With increasing volumes of heavy, high-sulfur crude oils becoming more commonplace, both the volumes and contaminant loadings of such wastewater are increasing in the refining industry. High nitrogen crude oils (notably Californian) result in high-ammonia-content sour waters that present particular treatment problems.

The purpose of the treatment of sour water is to remove sulfides (as H_2S, ammonium sulfide, and polysulfides) and ammonia before discharge to the sewer system; hence such treatment is considered "in-plant" as opposed to "end-of-pipe" treatment.

Sour water strippers have been designed primarily for the removal of sulfides and can be expected to achieve 85-99 percent removals. More recently, increased attention has been directed to the removal of ammonia to meet BPT limitations with such systems. Removal of ammonia is highly dependent on the stripping temperature, pH, and pounds of steam used per gallon of sour water. Whereas sulfide removals are enhanced by keeping the sour waters at a low pH, ammonia removals are enhanced by raising the pH. At those refineries where it is necessary to achieve high removals of both sulfides and ammonia, provisions have been made for multistage stripping or for ammonia removals in subsequent treatment steps.

The heated sour water is most commonly stripped with steam (air or flue gas have also been used) in single or multistage units, the latter for the purpose of separate removal of sulfides and ammonia where higher removal efficiencies are required. H_2S released from the wastewater can be recovered as sulfuric acid or sulfur. Ammonia released from the wastewater is normally incinerated in a furnace or combusted along with the H_2S in specially designed Claus sulfur recovery plants where the H_2S is recovered as sulfur and the ammonia is converted to nitrogen and water vapor.

Depending upon such conditions as pH, temperature, and contaminant partial pressure, phenols and cyanides are also partially removed by sour water stripping. Where practical, the stripped wastewater is re-used or recycled within the refinery for desalter make-up water, gas plant wash water for corrosion control, etc., with any balance discharged to the main refinery wastewater treatment plant. In some refineries the desalter effluent water is segregated and stripped separately prior to discharge to the sewer system.

Wastewater stripping facilities vary widely in size and complexity in the refining industry, depending upon crude oil types, refinery complexity, sour water volumes, and wastewater characteristics, along with regulatory limitations. Usually, stripping facilities require substantial volumes of steam; accordingly such treatment has a very high associated energy cost.

C. Spent Caustic Treatment

Caustic solutions are widely used in refining to neutralize and extract acidic materials contained in various process streams. Spent caustic solutions may therefore contain sulfides, mercaptides, sulfates, sulfonates, phenolates, naphthenates, and other similar organic and inorganic compounds.

While still extensively used, caustic treatment is being replaced in some instances by direct hydrogenation, particularly of heavier cracked hydrocarbon streams, which contain significant amounts of phenolic compounds. Also, caustic treating itself has evolved to where there is increasing application of regenerative-type systems, which virtually eliminate the generation of spent caustic requiring treatment and disposal.

Some refineries dispose of certain spent caustics by arrangement with outside firms that reclaim salable by-products. Most, however, provide for onsite treatment and/or disposal.

While there are a variety of different schemes used throughout the industry, it is common practice to pre-treat spent caustic by neutralization and then discharge it at a controlled rate into the main refinery wastewater treatment plant. In some cases the neutralized spent caustic is treated, again at a controlled rate, in the refinery sour water stripping facilities prior to discharge to the sewer to prevent discharge of excessive sulfide levels to the biotreatment plant and to suppress odors.

Some refineries incinerate spent caustics, thereby providing a satisfactory disposal method. However, incineration is an energy-intensive and costly disposal technique.

D. Primary Separation

Gravity separators remove most of the free oil and settleable solids found in refinery wastewaters. Removal of these contaminants is essential to the effective performance of subsequent wastewater treatment steps, and accordingly gravity separators are an integral part of any refinery wastewater treatment system. The effectiveness of a separator depends upon the temperature of the water, the density and size of the oil globules, the presence or absence of emulsifying substances, and the amounts and characteristics of the suspended matter present in the wastewater.

The API-design separator is the most widely used gravity separator.[30] The basic design is a long rectangular basin, with enough detention time for oil to float to the surface and the solids to the bottom. Provision is made to remove the separated oil and solids. The oil is subsequently treated and recovered and the solids are usually dewatered and disposed of as landfill or by land treatment.

The gravity separator usually consists of a pre-separator (grit chamber) and a main separator consisting of multiple rectangular

channels provided with influent and effluent flow distribution and stilling devices and with oil skimming and sludge collection equipment. It is essential that the velocity distribution of the approach flow be as uniform as possible.

Another type of separator being used increasingly in refineries is the parallel plate separator. The separator chamber is subdivided by parallel plates (usually corrugated) set at a 45° angle, less than 6 inches apart. This increases the collection area while decreasing the overall size of the unit. As the water flows down through the parallel plates, the oil droplets coalesce on the underside of the plates and travel upwards, where the oil is collected and removed. The solids collect in the bottom of the chamber and provision must be made for their removal.

E. Equalization

Following pre-treatment (e.g., stripping) and primary separation, those refinery wastewater streams containing colloidal or soluble materials requiring further treatment are usually combined and routed to equalization facilities. The purpose of equalization is to dampen out surges of contaminants, thereby providing a more constant wastewater feed quality to downstream treatment facilities. This is especially important for biological treatment systems, which rely on the health of a viable and active population of living microorganisms. Wide swings in the contaminant loadings to such a system can adversely affect the delicate balance necessary for effective treatment and, if severe enough, seriously impair the functioning of the biomass.

The equalization step involves the collection and mixing of the combined wastewaters in large ponds or tanks. Equalization capacity varies greatly for individual refineries and is often dictated by practical considerations such as land availability. As a general rule it is desirable to have a retention volume at least equal to the daily flow through the treatment plant.

F. Flocculation (Coagulation)

Chemical treatment to achieve coagulation and flocculation of the suspended materials in the equalized wastewater is often employed to enhance the physical removal of such materials in downstream units. The treatment involving the use of coagulants such as alum or cationic and anionic polymers results in the agglomeration of finely divided or colloidal particles, thereby making it easier to remove them either by sedimentation or flotation. Ideally the treatment is carried out separately in specially designed equipment provided with gentle mixing.

G. Dissolved Air Flotation

DAF consists of saturating a portion of the wastewater feed, or recycled effluent from the flotation unit, with air at a pressure of 40 to 60 pounds per square inch gauge. The wastewater or effluent recycle is held at this pressure for one to five minutes in

a retention tank and then released at atmospheric pressure to the flotation chamber. The sudden reduction in pressure results in the release of microscopic air bubbles, which attach themselves to oil and suspended particles in the wastewater in the flotation chamber. This results in agglomerates that, due to the entrained air, have greatly increased vertical rise rates of about 0.5 to 1.0 feet per minute. The floated materials rise to the surface to form a froth layer. Specially designed flight scrapers or other skimming devices continuously remove the froth. The retention time in the flotation chambers is usually about 10 to 30 minutes.

The effectiveness of DAF depends upon the attachment of bubbles to the suspended oil and other particles that are to be removed from the waste stream. The attraction between the air bubble and particle is a function of the particle surface and bubble-size distribution. Chemical flocculating agents, such as salts of iron and aluminum, with or without organic polyelectrolytes, are often helpful in improving the effectiveness of the air flotation process and in obtaining a high degree of clarification.

DAF is used by a number of refineries to treat the effluent from the oil/water separator. The froth skimmed from the flotation tank can be combined with other sludges (such as those from a gravity separator) for disposal. The clarified effluent from a flotation unit generally receives further treatment in a biological unit

H. Secondary Treatment

In wastewater treatment terminology, secondary treatment refers to biological treatment systems designed to remove oxygen-demanding constituents in the wastewater, with particular emphasis on soluble organics. A number of different systems employed in the refining industry are described below.

1. Oxidation Ponds

The oxidation pond is practical where land is plentiful and cheap. An oxidation pond has a large surface area and a shallow depth, usually not exceeding six feet. These ponds have long detention periods, from 11 to 110 days.

The oxidation pond operates aerobically without mechanical aerators because the high surface area to volume relationship allows transfer of sufficient additional atmospheric oxygen into the water at its surface. In addition, the algae in the pond produce oxygen through photosynthesis. This oxygen is then used by the bacteria to oxidize the wastes. Because of the low loadings, little biological sludge is produced and the pond is fairly resistant to upsets due to shock loadings.

Oxidation ponds are usually used as the major treatment process. Some refineries use ponds as a polishing process after other treatment processes.

2. Aerated Lagoon

The aerated lagoon is a smaller, deeper oxidation pond equipped with mechanical aerators or diffused air units. The addition of oxygen enables the aerated lagoon to support a higher concentration of microbes than the oxidation pond. The retention time in aerated lagoons is usually shorter, between three and 10 days. Most aerated lagoons are operated without final clarification. As a result, biological residues are discharged in the effluent, contributing to the effluent BOD_5 and solids concentrations.

As the effluent standards become more strict, final clarification will be increasing in use.

3. Trickling Filter

A trickling filter is an aerobic biological process. It differs from other processes in that the biomass is attached to the bed media, which may be rock, slag, or plastic. The filter works by absorption of organics by the biological slime, diffusion of air into the biomass, and oxidation of the dissolved organics. When the biomass reaches a certain thickness, part of it sloughs off. When the filter is used as the major treatment process, a clarifier is used to remove the sloughed biomass.

The trickling filter can be used either as the complete treatment system or as a roughing filter. Most applications in the petroleum industry use it as a roughing device to reduce the loading on an activated sludge system.

4. Activated Sludge

Activated sludge is an aerobic biological treatment process in which high concentrations [1,500-5,000 milligrams per liter (mg/l)] of newly grown and recycled microorganisms are suspended uniformly throughout a holding tank to which raw wastewaters are added. Oxygen is introduced by mechanical aerators, diffused air systems, or other means. The organic materials in the waste are removed from the aqueous phase by the microbiological growths and are stabilized by biochemical synthesis and oxidation reactions. The basic activated sludge process consists of an aeration tank followed by a sedimentation tank. The flocculent microbial growths removed in a sedimentation tank are recycled to the aeration tank to maintain a high concentration of active microorganisms. Although the microorganisms remove almost all of the organic matter from the waste being treated, much of the converted organic matter remains in the system in the form of microbial cells. These cells have a relatively high rate of oxygen demand and must be removed from the treated wastewater before discharge. Thus, final sedimentation and recirculation of biological solids are important elements in an activated sludge system.

Sludge is removed continuously to maintain an optimum sludge level in the system. Shock organic loads can result in an overloaded system and poor sludge settling characteristics. Effective

performance of activated sludge facilities requires pre-treatment to remove or substantially reduce oil, sulfides (which can be toxic to microorganisms), and phenol concentrations. The pre-treatment units most frequently used are gravity separators and air flotation units to remove oil, and sour water strippers to remove sulfides, mercaptans, and phenols. Equalization is usually provided to prevent shock loadings from upsetting the aeration basin. Because of the high rate and degree of organic stabilization possible with activated sludge, application of this process to the treatment of refinery wastewaters has been increasing rapidly in recent years.

Many variations of the activated sludge process are currently in use. Examples include the tapered aeration process, which has greater air addition at the influent where the oxygen demand is the highest; step aeration, which introduces the influent wastewater along the length of the aeration tank; and contact stabilization, in which the return sludge to the aeration tank is aerated for one to five hours. The contact stabilization process is useful where the oxygen demand is in the suspended or colloidal form. The completely mixed activated sludge plant uses large mechanical mixers to mix the influent with the contents of the aeration basin, decreasing the possibility of upsets due to shock loadings.

5. Rotating Biological Contactors

The Rotating Biological Contactors process utilizes a fixed-film biological reactor consisting of plastic media mounted on a horizontal shaft and placed in a tank. While wastewater flows through the tank, the media are slowly rotated, about 40 percent immersed, for contact with the wastewater to remove organic matter by the biological film that develops on the media. Rotation results in exposure of the film to the atmosphere as a means of aeration. Excess biomass on the media is stripped off by rotational shear forces, and the stripped solids are maintained in suspension by the mixing action of the rotating media. Multiple staging of Rotating Biological Contactors increases treatment efficiency. A complete system could consist of two or more parallel trains, each consisting of multiple stages in series.

The process has been in use in the United States only since 1969 and is not yet in widespread use. Use of the process has appeal, however, because of its characteristic modular construction, low hydraulic head loss, and shallow excavation, which make it adaptable to new or existing treatment facilities.

6. Secondary Clarification

Most biological systems employ secondary clarification to separate the biological solids (bio-sludge) to produce an effluent with an acceptable suspended solid content. In the case of an activated sludge system, clarifiers are used to separate the bio-sludge for recycle back to the aeration basins with the excess sludge being removed for ultimate disposal.

Clarifiers are generally specially designed large-diamater circular tanks equipped with a motor-driven revolving rake mechanism to collect and concentrate the settled sludge.

I. Tertiary Treatment

As a result of the high pollutant removals experienced with the extensive primary and secondary systems employed in the refining industry, general application of tertiary treatment is not practiced. Tertiary systems that have been used or experimented with include final filtration and the use of activated carbon. These systems are discussed briefly below.

1. Granular Media Filters

There are several types of granular media filters -- sand, dual media, and multimedia. These filters operate in basically the same way, the only difference being the filter media. The sand filter uses a relatively uniform grade of sand resting on a coarser material. The dual media filter has a coarse layer of coal above a fine layer of sand. Both types of filters have the problem of keeping the fine filter media particles on the bottom. This problem is solved by using a third, very heavy, very fine material (usually garnet) beneath the coal and sand.

As the water passes down through a filter, the suspended matter is caught in the pores. When the pressure drop through the filter becomes excessive, the flow through the filter is reversed for removal of the collected solids. The backwash occurs approximately once a day, depending upon the loading, and usually lasts for five to eight minutes.

2. Granular Activated Carbon

There is presently no application of a Granular Activated Carbon system in the refining industry. One refinery did install a granular carbon system designed to serve in place of secondary biological treatment. It proved unsuccessful and was abandoned, and a Rotating Biological Contactor conventional biological system has since been installed.

A major drawback of such systems is the fact that the influent water must already have received fairly extensive treatment to be amenable to carbon treatment. This being the case, only marginal further improvement can reasonably be expected. Another disadvantage is that for a system of even moderate size, provision would have to be made for regeneration of the carbon. Such systems have both high capital and operating costs, and it is unlikely that they will find application in the refining industry except in very special circumstances.

3. Powdered Activated Carbon

Experimental Powdered Activated Carbon (PAC) work has been carried out in the laboratory,[31,32,33] on pilot scale facilities,[34] and to a limited extent tests have been run in full-scale

activated sludge treatment (AST) plants.[35] These studies were primarily directed at efforts to see whether or not use of PAC would enhance the performance of AST systems to achieve BAT limits. These studies have demonstrated that PAC does enhance AST systems when they are operated at high sludge age, the PAC concentration in the aeration tank is greater than about 4,000 mg/l, and the PAC constitutes 50 percent or more of the recirculating solids. Typically, however, high sludge age operation itself has been demonstrated to achieve such excellent effluent quality from the AST system that effluent quality goals can be achieved without PAC enhancement.

J. Treatment Effectiveness

The refining industry as a whole is achieving removal efficiencies of better than 91 percent of the conventional water pollutants. Available data also indicate exceptionally high removals of the toxic or priority pollutants with BPT treatment technology.[36] Ranges of removal efficiencies for specific pollutants by type of treatment have been published by EPA.[37]

K. Wastewater Reduction and Re-use

To the extent practical, the refining industry employs water use conservation and re-use for a variety of compelling reasons. One major reason is to reduce wastewater volumes and, accordingly, the size and cost of construction and operation of treatment plant facilities.

On the basis of industry surveys, wastewater flow volumes per barrel of crude oil run were reduced an average of 55 percent for direct dischargers between the years 1972 and 1977.[38] This reflects the fact that the industry has sufficient incentive to reduce wastewater volumes as a practical matter. It is important to note, however, that there are a number of factors that determine the cost and feasibility of flow reduction/re-use practices in a given refinery and, accordingly, such measures can be properly considered only on a plant-by-plant basis. Some of the factors are refinery size, age, and complexity; crude oil type; and water supply availability and type (salt, brackish, or fresh).

A number of water conservation practices can sometimes be incorporated into refinery operations. These include:

- Increased use of air cooling which may increase energy costs
- Use of storm water ponds for fire water systems
- Use of sour water and/or vacuum ejector water for desalter wash water make-up
- Use of stripped sour water for desalter wash water make-up and/or gas plant wash water (for corrosion control)

- Replacement of barometric condensers with surface condensers or other vacuum producing systems

- Process modifications that have reduced water requirements

- Use of closed pump gland cooling water systems (this is generally restricted to new installations)

- Re-use of wastewater treatment plant effluent for certain refinery water use applications such as cooling tower make-up, pump gland cooling systems, wash down waters, and fire water systems. Re-use of treated wastewater for these purposes requires investigation on an individual refinery basis to determine technical and economic feasibility.

V. Solids Removal and Dewatering

A. Sources of Solids

Solids can enter refinery wastewater from a number of sources, including process operations that involve the use or production of solids such as catalytic crackers or cokers. In many instances a major and sometimes predominant source of solids is the water supply source itself. In addition, storm water runoff can add measurably to solids entry.

In addition to solids that enter the system, biological treatment of wastewater generates bio-sludge. Another potential source of solids in treated wastewater results from the growth of algae in polishing ponds downstream of wastewater treatment facilities.

B. Treatment

A variety of treatment options are used to remove and dewater solids in wastewater. The bulk of the solids that enter the sewer system are removed in primary and secondary separation treatment steps. Such solids are removed as sludge from the bottom of gravity separators and additional solids are removed along with the free oil skimmings from these same separators as well as in the float or scum from air flotation units.

Dewatering of these solids, which contain oil as well as water, can be accomplished by use of heat and chemical treatment or by standard mechanical separation techniques using centrifuges or filtration (pressure, vacuum, or gravity). In many instances, effective dewatering requires combined use of heat, chemical treatment, and mechanical separation.

Bio-sludge removed from biological treatment systems usually receives multi-stage treatment prior to final disposal. In some systems these solids are thickened, subjected to aerobic digestion (to stabilize the solids and reduce volatile solids), and then mechanically dewatered. The final disposal of the dewatered sludges is discussed elsewhere in this report.

VI. Oil Recovery and Treatment

The recovery and treatment practices just discussed apply to oil removed from the primary and secondary separation stages of wastewater treatment. One major difference is that emphasis is on reclaiming the oil for reprocessing or for use as a fuel.

In most refineries, oil recovered from wastewater treatment is returned to the coker or crude oil unit. This being the case, it is important that essentially all of the water and solids first be removed. Accordingly, treatment of the "wet" oil is generally more rigorous than that employed for the dewatering of solids. Heat and chemical treatment are commonly used to "break" emulsified oil. In most cases the majority of the oil thus separated is suitable without further treatment for reprocessing. There usually remains, however, a middle layer of emulsified oil or "cuff" requiring further treatment or disposal. Further treatment generally consists of mechanical separation by centrifuging or filtration. Where separate solids dewatering facilities are provided, these can be used to treat the "cuff" from the oil recovery system.

VII. Effluent Monitoring

NPDES permits issued to individual refineries set forth the parameters and frequency of sampling and testing required to determine compliance with applicable limitations. In addition, at least some permits specify additional sampling and testing requirements to monitor treatment plant performance. Beyond these specified requirements, refineries establish monitoring programs to assist in their overall wastewater management programs. For those parameters included as a permit requirement, sampling and testing methods designated in the Code of Federal Regulations must be used.[39] There are two general categories of effluent monitoring: physical or chemical monitoring, and biological monitoring.

A. Physical or Chemical Monitoring

Physical or chemical monitoring involves the measurement of parameters such as temperature, TSP, pH, BOD, TOC or COD, O&G, phenols, sulfides, ammonia, cyanide, and chromates.

B. Biological Monitoring (Bioassay)

Bioassay testing measures the susceptibility of living organisms to the combined constituents in treated wastewater. Use of one of a variety of different fish species is most common. Invertebrates such as shrimp or water fleas (daphnia) are also used in some instances. Bioassay testing requires extreme care in preparation of the species, the performance of the actual test, and in the final interpretation of the results.

Bioassays are generally run over a range of wastewater concentrations to determine acute toxicity expressed as the median tolerance limit. This concentration of treated wastewater is a suitable diluent at which 50 percent of the test organisms are

killed over a specified period of exposure. Biologically "safe" concentrations against acute toxicity are generally considered to be from one-half to one-third of the median tolerance limit.

C. Priority Pollutant Testing

With passage of the Clean Water Act Amendments of 1977 and subsequent identification of the 129 specific compounds on the priority pollutant list, new sampling and testing requirements have been established. Specifically, refineries that apply for renewal of NPDES permits must submit priority pollutant analyses for their existing discharges.

The analytical procedures involve the use of gas chromatography/mass spectroscopy techniques requiring very sophisticated and expensive analytical equipment that is capable of measuring exceptionally low concentrations. Because the concentrations sought are so low, it is critical that great care be exercised to avoid outside contamination of the wastewater samples and that highly trained personnel conduct the testing. Most refineries do not have the capability of running these tests and rely on outside laboratories specializing in this type of analytical work.

WASTE MANAGEMENT

I. Applicable Laws and Regulations

Environmental laws and regulations enacted within the last decade were designed to regulate pollutants within a specific medium. More recently, the Resource Conservation and Recovery Act of 1976 (RCRA), and the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) (Superfund), unlike the Clean Water Act or the Clean Air Act, have attempted a comprehensive approach to the control of waste management practices. These laws are briefly discussed in Chapter One. RCRA addresses the management of new and existing waste management facilities, and CERCLA outlines governmental and private actions to correct past waste disposal problems.

The National Groundwater Strategy Program being developed by EPA is also expected to have provisions providing for controlling land pollution, thereby protecting groundwater aquifers. It is likely that BMP and Good Engineering Practices will constitute part of the regulatory control strategy.

II. Definition of Hazardous Wastes

The present federal waste management approach either identifies a waste as hazardous, and therefore subject to regulation, or completely excludes it from the regulatory program. All hazardous wastes are subject to identical controls, which may fail to recognize the significant difference in degree-of-hazard for different materials. Many large-volume wastes in the refining sector have had to be defined as hazardous, although their degree of hazard is

minor. This contributes to the shortfall of needed capacity to dispose of truly hazardous wastes. In most instances, however, refining wastes do not require the same stringent disposal requirements established for truly hazardous wastes.

Further confusion can also arise from differences in the regulatory definitions of hazardous wastes between state and federal governments. Many states have expressly conformed their definitions of hazardous wastes with those of RCRA. Other states have their own definitions, which may or may not be substantially equivalent to EPA's or ultimately approved by EPA. Some states have passed legislation setting up study programs to develop standards and criteria for identifying hazardous wastes. Several states have recognized degrees-of-hazard and incorporated applicable control requirements in their regulations.[40] Unfortunately, the criteria used by the states for such characterization have differed widely. As a result, significant variations exist among their definitions of hazardous waste materials. Moreover, new categories have been established, such as "extremely hazardous," that further complicate the management and disposal of those substances.

III. Refinery Wastes Listed as Hazardous Under RCRA

Refinery wastes listed in 1981 as hazardous under RCRA regulations are summarized in Table 41. The following possible changes in direction are significant to the petroleum industry:

(1) The listed hazardous wastes (K048, K049, K050, K051, and K052) were so designated because each waste stream typically contains lead and/or chromium. According to the RCRA regulations, lead and chromium are extraction procedure (EP) toxic metals Preliminary testing suggests that EP leachate from all these wastes has concentrations of lead and/or chromium less than 100 times the National Interim Primary Drinking Water Standards. It is therefore possible that these wastes could be delisted in the future. EPA is also considering restricting chromium toxicity criteria to the hexavalent variety, which may provide proper exemption to other forms of chromium in hazardous waste regimes. The listed hazardous waste K050 is now considered nonhazardous if washed to the wastewater treatment system

(2) Wastes not specifically listed in the regulations must be tested to determine if they are hazardous due to ignitability, corrosivity, reactivity, or EP toxicity. More than four times as many petroleum wastes are defined as hazardous by these four characteristics than are listed in the regulations [41] EPA has considered adding tests for carcinogenicity, mutagenicity, teratogenicity, and radioactivity Additional test criteria may identify additional petroleum wastes as hazardous.

TABLE 41

Hazardous Wastes of the Petroleum Refining Industry as Defined by the RCRA Regulations (May 1981)

Listed Hazardous Waste Streams (§261.32)

K048 -- Dissolved Air Flotation (DAF) Float

K049 -- Slop Oil Emulsion Solids

K050 -- Heat Exchanger Bundle Cleaning Sludge

K051 -- API Separator Sludge

K052 -- Tank Bottoms (Leaded)

(3) Oil spills to land, and spent automotive and industrial oils, may be added to the federal listing of hazardous wastes and regulated under the RCRA Part 266 regulations, which are proposed waste oil regulations scheduled to be published in 1982. A 1978 report estimated that 196,000,000 gallons per year of waste oil and 417,000 cubic yards per year of oil spill debris are generated by the petroleum industry.[42] The potential scope of the waste oil regulations is very broad and therefore its impact upon the industry may be a major one.

(4) Waste crude oil may also be covered under the proposed Part 266 of the RCRA regulations,[43] and the EPA Administrator's letter to Congress, dated January 16, 1981, clearly identifies waste crude oil as hazardous waste.[44] In all probability, such new regulations could increase the requirements for approved hazardous waste disposal sites manyfold.

IV. Amount of Wastes Generated

A number of factors may affect the volume of hazardous wastes generated by the petroleum refining industry during the next ten years. As already indicated, additions or deletions from the hazardous waste list will be very important. Increased production, changing feedstocks such as synfuels, and process modifications may change the volume and character of waste streams. Changes in waste handling practices will likely reduce the amount of material requiring secure disposal; for example, neutralization and dewatering procedures will receive greater emphasis. There is, therefore, considerable uncertainty as to the amount of wastes generated by the petroleum industry.

Estimates of the amounts of hazardous wastes generated by industry and the nation's commercial disposal capacity are summarized in Table 42. The refining sector generated less than 5 percent of the total of hazardous wastes generated, and used only 1.4 percent of the available (1980) offsite commercial disposal capacity. All industry used less than 24 percent of the estimated available offsite commercial disposal capacity in 1980.

TABLE 42

Industrial Hazardous Waste Generation and Disposal -- 1980

	Thousands of WMT†	Percentage
National Commercial Disposal Capacity, Total		
Landfill	27,604	--
Other (e.g., Incineration, Deep Well)	12,754	--
Total	40,358	--
National Industrial Sources		
Total Generation	41,240	--
Disposal Offsite	9,485	23
Percentage of National Commercial Capacity Used	--	23.5
Refining Sector Sources		
Total Generation	1,901	--
Disposed Offsite	570	30
Percentage of National Commercial Capacity Used	--	1.4
Percentage of Total Offsite Disposal	--	6
Percentage of Total Industrial Hazardous Wastes	--	4.6

*Source of data: Booz, Allen and Hamilton, Incorporated, and Putnam, Hayes and Bartlett, Incorporated, for the U.S. Environmental Protection Agency, Hazardous Waste Generation and Commercial Hazardous Waste Management Capacity -- An Assessment, December 1980.

†WMT = wet metric tons.

While the aforementioned data provide a reference point for estimating the amount of hazardous waste generated by refineries, the accuracy of the estimate has been questioned by industry groups. Other sources are also considered to be poor data bases for estimating the current situation. These latter sources include the 1976 Jacobs study,[45] a survey by Engineering Science,[46] and a survey of Canadian refineries.[47] The Jacobs study reported data from a 1974 survey of only 16 refineries representing 18 percent of U.S refining capacity. The Engineering Science study

reported data from a 1976 study of 78 refineries representing 57 percent of U.S. capacity, but the data base was prior to waste quantities generated by 1977 BPT facilities, estimated prior to RCRA definitions, and does not account for delisted streams. The Canadian study accounts for 100 percent of the Canadian refineries in 1980 and the results suggest that earlier U.S. studies significantly underestimated the amount of hazardous wastes generated. Clearly, a better data base is needed for the refining sector.

V. Present Waste Disposal Practices

Several disposal options are presently used for petroleum wastes. The more prevalent are landfilling, landtreating, and reclamation. Incineration is currently used for only a small percentage of petroleum refining wastes.[48] Few changes in treatment technology alternatives are expected to emerge in response to demands resulting from the RCRA disposal regulations. However, the RCRA regulations may ultimately cause a shift in the treatment methodology utilized, from land disposal to incineration. Increased use of such processes as oil recovery and dewatering, as well as stricter source control measures, will reduce the quantity of solids requiring specialized hazardous waste disposal.

Table 43 is specific to refinery waste streams and estimated percentages of onsite and offsite waste disposal by method. Landfilling is presently the most widely used method for disposing of petroleum refinery wastes.

TABLE 43

Estimates of Refinery Waste
Disposal Methodologies Utilized -- 1973 and 1983*
(Percentages)

Disposal Procedure	1973 Onsite	1973 Offsite	1983 Onsite	1983 Offsite
Landfilling	16.8	34.3	24	20
Lagooning	18.3	21.4	12	7
Incineration	0.8	0	3	0
Land Treatment	8.4	0	34	0
Total	44.3	55.7	73	27

*Source of data: Jacobs Engineering Company, "Assessment of Hazardous Waste Practices in the Petroleum Refining Industry," June 1976.

Land treatment (or landfarming) is a relatively inexpensive treatment/disposal method being used by a growing number of facilities for disposing of oily waste sludges. Land treatment may be used for treatment/disposal of wastes such as biological treatment solids, API separator sludges, tank bottoms, slop oil emulsion solids, and flotation float. Land treatment is a process whereby a controlled amount of waste is spread and mixed by cultivating it into the surface soil at a disposal site. Degradation of organic wastes is carried out by naturally occurring microbial activity and chemical or photochemical processes under proper controls. Land treatment is almost exclusively conducted onsite or at sites owned or controlled by the refiner. The industry believes that land treatment may be the most environmentally acceptable treatment/ disposal method for oily waste.

Within the refining industry, pits, ponds, and lagoons are being phased out as disposal methods. More stringent regulatory requirements have caused a shift to landtreating and landfilling disposal technologies. In the future, however, the RCRA regulations may result in a shift from land disposal to incineration.

Incineration is a potential disposal method for DAF sludge, API separator sludge, slop oil emulsion solids, and other oily wastes. It is rarely used at present, because incineration is more costly and energy intensive than land disposal methods.

VI. Capacity -- Existing and Projected

RCRA requires that sites for the storage, treatment, or disposal of hazardous wastes be managed to protect the public health and environment. As a consequence of stringent regulations that took effect in November 1980, many existing disposal sites closed or discontinued accepting hazardous wastes. A shortage of approved landfills already exists in many areas of the country. To compound the problem, permit rules and local public opposition are restricting the construction of new facilities. The resulting shortfall of hazardous waste treatment/disposal capacity will adversely impact future petroleum industry operations.

The siting problem has many facets. The definition of what is hazardous substantially influences the volume of hazardous wastes generated, and, in turn, the demand for disposal capacity in secure facilities. Yet hazardous petroleum wastes do not pose environmental risks as great as substances like pesticides. Permit criteria that limit available disposal alternatives will further aggravate the capacity shortage. For example, regulations proposed in 1981 would severely curtail ongoing land disposal of ignitable and oily petroleum wastes. Restrictions on site locations will increase the proportion of offsite disposal as industry's onsite capacity is consumed. Disposal costs will rise accordingly. Finally, local prohibitions against new facilities frustrate compliance by denying industry the necessary disposal capacity.

Table 44 estimates the capacity, by EPA region, of offsite commercial hazardous waste disposal facilities. Comparison of

TABLE 44

Comparison of 1981 Offsite Capacity Demand and Supply by EPA Region and Projected Capacity Expansions*
(Thousands of Wet Metric Tons)

EPA Region	Most Probable Offsite Demand in 1981	Estimated Annual Capacity at the Beginning of 1981	Difference
I	580	218	-362
II	1,022	2,139	1,117
III	922	1,202	280
IV	1,358	1,566†	208
V	2,517	2,028	-489
VI	1,346	7,981†	6,635
VII	440	218	-222
VIII	154	--	-154
IX	896	2,759	1,863
X	503	318	-185

*Source of data: Booz, Allen and Hamilton, Incorporated, and Putnam, Hayes and Bartlett, Incorporated, for the U.S. Environmental Protection Agency, Hazardous Waste Generation and Commercial Hazardous Waste Management Capacity -- An Assessment, December 1980.

†The land treatment capacity of Region IV is included in the Region VI estimate.

capacity supply and demand, at the regional level, illustrates that neither is evenly distributed. Some areas of the country face little or no immediate shortfall problem, while others (Region V, for example) are presently experiencing local capacity shortfalls. Transportation costs for shipping large volumes of wastes long distances to available capacity in another location may be economically unfeasible. Such shipments will also increase the potential for accidents and spills. Thus, despite an apparent national adequacy, localized shortfalls are indicated to be a significant

obstacle to proper hazardous waste disposal. There is a need to match the location of hazardous waste management facilities with the needs for disposal. In other words, regional availability does not always solve a local shortage.

Figure 55 illustrates the geographic location, in June 1980, of existing commercial treatment and disposal facilities within the United States. Many commercial hazardous waste management facilities have since closed. For example, in 1980, 14 hazardous waste disposal facility operators were identified as operating in Region IX.[49] Of these 14 facilities, four have been closed, two accept only limited types of wastes, and two more are the targets of numerous citizen complaints. Within Region V, eight facilities were reportedly operating in Indiana. Three of the eight facilities have been closed or are the subject of an enforcement action by EPA. Three additional facilities are under investigation.

Several other factors will compound the imminent shortfall problem in the next 10 years. The RCRA permit regulations may require that the petroleum industry change from land disposal to incineration to dispose of its hazardous wastes. Therefore, a greater number of hazardous waste incinerators may be needed. Unfortunately, public opposition has resulted in a number of state and local laws that effectively ban the construction of new hazardous waste management facilities. Should these trends continue, the necessary siting and construction will not occur. Additional demand for hazardous waste management facilities may arise when CERCLA-affected abandoned sites are cleaned up.

VII. State and Local Siting Controls

Public opposition to new facilities is the major obstacle to the siting of new hazardous waste management facilities. A 1980 public opinion survey conducted by the White House Council on Environmental Quality found that a majority of citizens endorsed the need for new, well-run disposal facilities, but only if they were located 100 miles from their homes. The public fears groundwater contamination, air pollution, cancer, and birth defects. RCRA Subtitle C permitting requires public participation. Local opposition by such means as zoning ordinances can cause numerous delays in the permitting process, effectively prohibiting construction of a new facility. For example, local opposition to the siting of a hazardous waste facility in Michigan has escalated the controversy to the state supreme court.

While states generally have legislative prerogative to pass laws that pre-empt local zoning bans against new hazardous waste management facilities, most states are hesitant to do so. More states have passed laws restricting or banning the construction of new hazardous waste sites than have passed pre-emptive legislation. Pre-emptive legislation is still subject to local political pressure. In an attempt to solve the siting problem, several states have established siting boards, which provide for public participation and have the authority to pre-empt local restrictions (Michigan, Wisconsin, Indiana, New York, Washington, New Jersey, and Massachusetts).

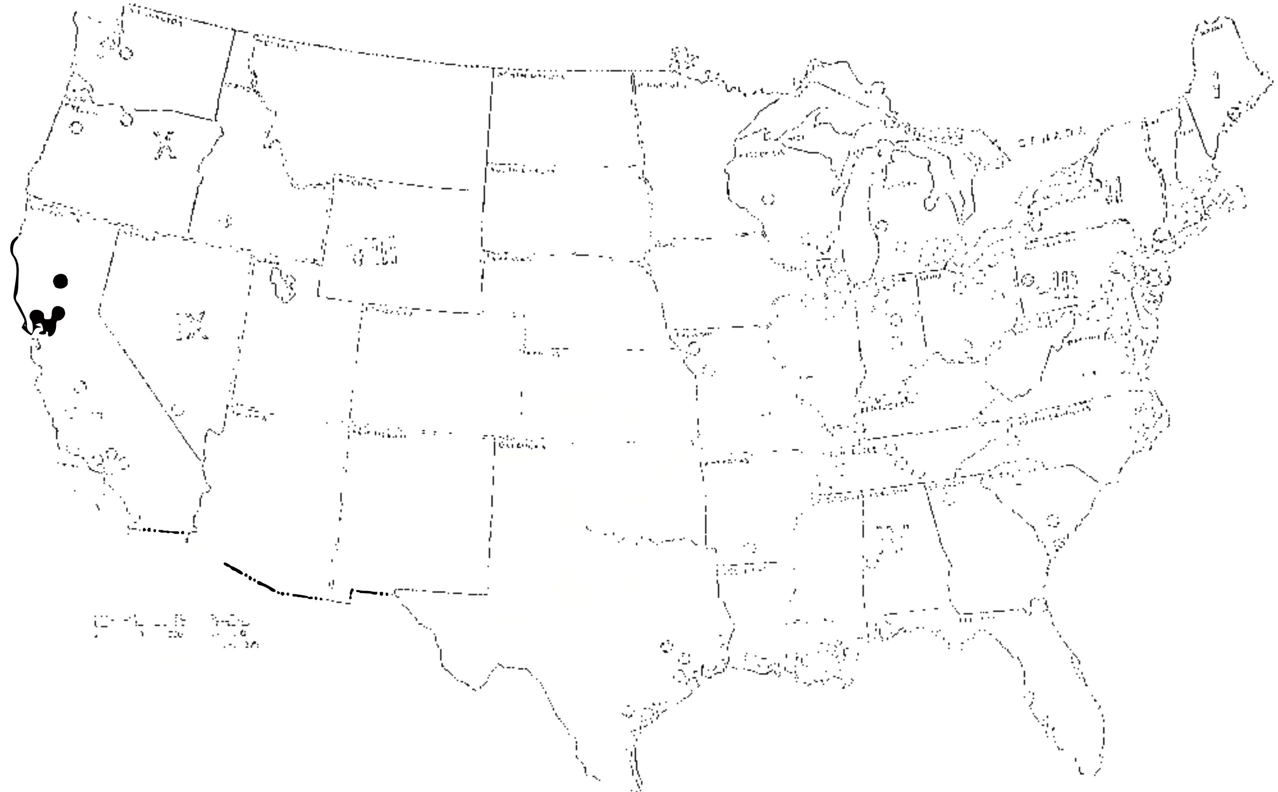


Figure 55. Geographic Locations of All Identified Commercial Hazardous Waste Management Facilities—June 1980.

NOTE: Includes facilities engaged in the treatment and disposal of hazardous waste for a fee, but does not include solvent buying, selling, or recovery operations or storage and transfer stations that may be handling wastes classified as hazardous; subsequent to June 1980, a number of these facilities closed or restricted their operations while a few started operations.

SOURCE: Booz, Allen and Hamilton, Incorporated, and Putnam, Hayes and Bartlett, Incorporated, for the U.S. Environmental Protection Agency, *Hazardous Waste Generation and Commercial Hazardous Waste Management Capacity–An Assessment*, December 1980.

The federal government, via CERCLA legislation, has attempted to provide incentives for each state to ensure the siting of new hazardous waste facilities. CERCLA prevents a state from acquiring federal grant monies if that state does not have access to at least one hazardous waste disposal facility located in the state. Local and state authorities have not as yet adequately addressed the siting problem.

One approach to the solution of the potential lack of disposal facilities is legislation to establish and control such facilities in a manner similar to that of public trusts. Private or publicly owned hazardous waste disposal corporations would be encouraged by appropriate federal and state legislation to establish and operate disposal sites on properly designated lands. Proper schedules of charges for disposal, together with a regulated profit margin, would be authorized. Proper compliance with construction, operation, maintenance, recordkeeping, and closure standards would be assured under terms of the site contract as well as regulatory provisions in the enabling legislation. After final closure, the land would revert to the federal and/or state government for stabilization and containment of the waste in perpetuity. Such an organization could assure the nation that hazardous wastes would be handled safely and in compliance with all applicable control requirements.

VIII. RCRA Permit Requirements

RCRA permit requirements will significantly alter the supply and demand for hazardous waste management facilities. The supply of these facilities will be reduced because some existing facilities will fill to capacity, while others cannot comply with the regulations and therefore must close. The demand for hazardous waste management facilities may increase as more wastes are defined as hazardous under RCRA and must be managed accordingly.

A brief history of EPA's land disposal regulations (which had not been promulgated as of December 1981) illustrates the vacillating regulatory framework of the RCRA hazardous waste management program. Early in 1981, EPA proposed land disposal standards for owners and operators of hazardous waste storage, treatment, and disposal facilities under Part 264 of RCRA. The goal of these regulations is to protect our nation's groundwater, but the requirements of the proposed land disposal regulations were technically unattainable. After numerous public comments, the Agency decided to reconsider these regulations and to survey the land treatment and disposal practices of several major industries. EPA projected reproposal of the land disposal regulations in 1983. However, the U.S. District Court of the District of Columbia has ordered EPA to promulgate final regulations by February 1, 1982.[50] EPA has been ordered to promulgate regulations without the benefit of specific waste stream assessments, which would facilitate a degree-of-hazard regulatory approach. It is likely that any regulation promulgated to meet this court-imposed deadline will require modification and at least administrative interpretation for quite some time during the next decade.

Under Part 264 of RCRA and other federal laws such as the Coastal Zone Management Act, EPA regulates the location of hazardous waste management facilities. Specifically, the Part 264 regulations may prohibit the expansion of an existing facility or the construction of new facilities dependent upon seismic considerations and floodplain distances. In addition, EPA is temporarily deferring a final regulation on siting restrictions in coastal high hazard areas. Site selection restrictions could result in increased transportation costs for hazardous waste disposal, particularly in the coastal regions, where much of the petroleum industry is presently located.

Finally, EPA is predicting that the final permit regulations will not be promulgated for several years and that it will need approximately five years to process the permit applications and issue all the permits. These administrative delays will only aggravate the disposal capacity shortfall.

IX. Future Trends

The RCRA regulations of greatest significance to the petroleum industry are not yet promulgated, and the remaining capacity at private and commercial hazardous waste disposal sites is uncertain. Thus, any assessment of the impact of siting on this industry's operations is somewhat tenuous. It is estimated that the petroleum industry currently handles about 70 percent of its own RCRA hazardous waste. By 1983, it has been projected that roughly half of the onsite waste will be landfarmed and the rest will be placed in landfills. Properly operated landfarms could continue to be used almost indefinitely. Without an effective mechanism for siting new hazardous waste landfills, it is projected that existing landfill capacity will be generally exhausted within the next several years.

The potential exists for the shortage of hazardous waste disposal sites to pose critical problems to this industry's operations. The RCRA regulations will probably be expanded to encompass waste oils and other substances that were not previously designated as hazardous, thus increasing the volume of hazardous wastes to be disposed. On the other hand, the RCRA permit regulations, as proposed, effectively prohibit the land disposal of oily wastes. Should this regulation become effective, the amount of hazardous wastes that were landfilled or landtreated must be shunted to incinerator disposal units. It should be noted that commercial incineration capacities are presently near ceiling and the refining segment has only minimal incineration capacity.

Public opposition has effectively restricted the siting of new hazardous waste facilities, be they incinerators or landfills. Federal and state governments must take action to ensure that this shortage is remedied.

In spite of what appears to be a rather pessimistic account of the problems that are faced in managing the proper disposal of hazardous petroleum wastes, as well as bleak forecasts for the future, the U.S. petroleum industry has in the past and will in the

future respond with positive and progressive remedial programs if the proper climate is available within the regulatory structure.

The presently available information regarding petroleum industry hazardous waste is limited. An industry-wide waste inventory is needed to identify hazardous waste streams by operation or source and volume. Disposal cost information should also be included in such a survey.

Landfarming, bio-oxidation, composting, and related low cost, self-sustaining, highly efficient, and environmentally enhancing technologies will be the basis for hazardous waste disposal systems for the next generation. In many parts of the country, these methods can be implemented on property that is owned and controlled by the petroleum companies without encroaching on private or municipal domains. Stronger support by both federal and state government is necessary for the development of these technologies.

ENVIRONMENTAL EXPENDITURES

The petroleum refining industry has a consistent and sustained record of environmental expenditures as shown by the data in Table 45 from the annual API survey.[51] Over the past decade the industry has invested over $5 billion in environmental facilities, almost $8 billion in operating the facilities, and two-thirds of a billion dollars in research. The total expenditures of $13,655 million spent by the refining sector represents about 65 percent of the total pollution control expenditures by the industry.

Capital spending for water pollution abatement peaked in 1976-1977 as refiners upgraded their water treatment facilities to assure meeting the July 1, 1977, NPDES permit requirements. Currently, RCRA and CERCLA are anticipated to increase environmental expenditures markedly in the land (other) category. Capital expenditures for air pollution abatement facilities averaged more than 70 percent of the total environmental capital expenditures in the refining sector during the last decade, and are expected to continue at a high level in order to allow processing of lower quality feedstocks.

In 1980, the most recent year for which data are available, environmental capital expenditures for the refining sector were at a record level of two-thirds of a billion dollars. The cost of operating these facilities is approaching $2 billion a year.

A Battelle study reports that the cumulative capital environmental expenditures for the refining sector have reached $17 billion (1979 dollars) in 1980 and predicts that the cumulative capital expenditures will reach $30 billion (1979 dollars) by 1990, excluding RCRA related costs.[52]

TABLE 45

Environmental Expenditures in the Petroleum Refining Sector -- 1971-1980
(Millions of Dollars)

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	Total 1971-1980
Capital Expenditures											
Air	$329	$264	$369	$373	$450	$385	$230	$332	$448	$498	$3,678
Water	112	86	93	123	130	203	189	83	100	123	1,242
Land and Other	27	7	8	16	13	8	21	8	14	35	157
Subtotal	$468	$357	$470	$512	$593	$596	$440	$423	$562	$656	$5,077
Administrative, Operating, & Maintenance Expenditures											
Air	$116	$172	$214	$291	$328	$574	$723	$791	$913	$1,262	$5,384
Water	75	100	109	126	136	227	311	320	367	476	2,247
Land and Other	13	8	10	13	15	19	34	34	47	86	279
Subtotal	$204	$280	$333	$430	$479	$820	$1,068	$1,145	$1,327	$1,824	$7,910
Research and Development											
Air	$37	$47	$50	$53	$49	$45	$57	$56	$58	$64	$516
Water	6	8	7	10	11	10	14	12	13	18	109
Land and Other	3	3	5	3	5	4	2	4	5	9	43
Subtotal	$46	$58	$62	$66	$65	$59	$73	$72	$76	$91	$668
Total	$718	$695	$65	$1,008	$1,137	$1,475	$1,581	$1,640	$1,965	$2,571	$13,655

SOURCE: American Petroleum Institute, Environmental Expenditures of the United States Petroleum Industry, 1971-1980, 1981.

REFERENCES AND NOTES

[1]American Petroleum Institute, Basic Petroleum Data Book, 1981.

[2]Code of Federal Regulations, 40 CFR 60, Subpart J.

[3]Code of Federal Regulations, 40 CFR 60, Subparts K and Ka.

[4]American Petroleum Institute, Environmental Expenditures of the United States Petroleum Industry, 1971-1980, 1981.

[5]National Commission on Air Quality, To Breathe Clean Air, March 1981.

[6]Under EPA's offset ruling, "banking" of offsets is allowed in order to offset future growth. However, the states are given discretion in deciding whether the source may retain control of banked emissions and how these banked offsets will be allocated. Credit for source shutdowns and curtailments may also be obtained and banked if the shutdown occurred after August 7, 1977, or less than one year before the date of the new source permit application, whichever is earlier.

[7]Case histories excerpted from Environmental Research & Technology, Inc., for The Business Roundtable, Effects of the Clean Air Act in Industrial Planning and Development, Vols. I and II, July 1981.

[8]Adapted from American Petroleum Institute, Manual on Disposal of Refinery Wastes, 1977.

[9]House Committee on Public Works, Subcommittee on Oversight and Review, Implementation of the Federal Water Pollution Control Act, December 1980.

[10]The specific requirements as promulgated can be found in "Effluent Guidelines and Standards for Petroleum Refining," Code of Federal Regulations, 40 CFR 419.

[11]Background information relating to these guidelines and standards is contained in the Environmental Protection Agency's Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Petroleum Refining Point Source Category, April 1974.

[12]Ibid.

[13]Environmental Protection Agency, "Petroleum Refining Point Source Category Effluent Limitations Guidelines, Pretreatment Standards, and New Source Performance Standards," Proposed Rule 44 FR 75926, December 21, 1979 (hereafter referred to as EPA, "Proposed Effluent Limitations Guidelines").

[14]Ibid.

[15]American Petroleum Institute, "Comments of the American Petroleum Institute Regarding the Environmental Protection Agency's Proposed Effluent Limitations Guidelines, Pretreatment Standards and New Source Performance Standards for the Petroleum Refining Point Source Category," 1980 (hereafter referred to as API, "Comments").

[16]American Petroleum Institute, Evaluation of Cost-Reasonableness of Best Conventional Technology Regulations for the Petroleum Refining Point Source Category, June 1980 (hereafter referred to as API, "Cost-Reasonableness Evaluation").

[17]American Petroleum Institute, Technical Evaluation of the Best Available Technology Economically Achievable (BAT) Effluent Limitations Guidelines for the Petroleum Refining Point Source Category, June 1980.

[18]Code of Federal Regulations, 40 CFR 419.71.

[19]Federal Register, 44 FR 44501.

[20]American Paper Institute vs. U.S. Environmental Protection Agency, nos. 79-1511 et al. (decided July 28, 1981).

[21]API, "Comments," op. cit.

[22]Regulations dealing with this subject promulgated under authority of Section 311 of the Clean Water Act can be found in Code of Federal Regulations 40 CFR Parts 110, 112, 113, 114, and 115. Additional regulations are found in 46 CFR Part 542 as well as at 33 CFR Parts 153, 154, 155, and 156.

[23]Crossley, S-D Surveys, Inc., for the American Petroleum Institute, 1967 Domestic Refinery Effluent Profile, September 1968.

[24]EPA, "Proposed Effluent Limitations Guidelines," op. cit.

[25]Environmental Protection Agency, "Economic Analysis of Proposed Revised Effluent Standards and Limitations for the Petroleum Refining Industry," November 1979.

[26]API, "Cost-Reasonableness Evaluation," op. cit.

[27]Federal Register, 44 FR 75931.

[28]Ibid.

[29]API, "Cost-Reasonableness Evaluation," op. cit.

[30]American Petroleum Institute, Manual on Disposal of Refinery Wastes, Volume on Liquid Wastes, 1969.

[31]American Petroleum Institute, Pilot Studies on Enhancement of the Refinery Activated Sludge Process, October 1977.

[32]American Petroleum Institute, Pilot Studies on Enhancement of the Refinery Activated Sludge Process - Phase II, October 1978.

[33]Grieves, C. G.; Stenstron, M. K.; Walk, J. D.; Grutch, J. F., "Powdered Activated Carbon Improves Activated Sludge Treatment," Hydrocarbon Processing, October 1977.

[34]Grieves, C. G., et al., "Powdered Activated Carbon Enhancement versus Granular Carbon Adsorption for Oil Refinery BETEA Wastewater Treatment," Water Pollution Control Federation Meeting, Anaheim, California, October 1978.

[35]Grutch, J. F.; Kloeckner, D. C.; Moore, J. S., "Maximizing Effluent Quality from a Municipal Activated Sludge Plant Concurrent with a Major Reduction in Process Energy Requirements," American Institute of Chemical Engineers Meeting, Chicago, Illinois, November 20, 1980; published in Water - 1980, AICHE Symposium Series.

[36]EPA, "Proposed Effluent Limitations Guidelines," op. cit.

[37]Environmental Protection Agency, Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Petroleum Refining Point Source Category, April 1974; Table 28.

[38]Environmental Protection Agency, Proposed Development Document for Effluent Limitations Guidelines and Standards for the Petroleum Refining Point Source Category, December 1979.

[39]Code of Federal Regulations, 40 CFR 136.

[40]Simcoe, B.; Warren, J. Hazardous Waste Management: A Survey of State Laws 1976-1979, National Conference of State Legislatures, February 1980.

[41]Booz, Allen and Hamilton, Incorporated, and Putnam, Hayes and Bartlett, Incorporated, for the U.S. Environmental Protection Agency, Hazardous Waste Generation and Commercial Hazardous Waste Management Capacity -- An Assessment, December 1980.

[42]SCS Engineers, for the American Petroleum Institute, Assessment of Petroleum Industry Cost of Compliance with Proposed Hazardous Waste Regulations, April 1979.

[43]Environmental Protection Agency, "Draft Waste Oil Regulations," April 10, 1981.

[44]Douglas M. Costle, EPA Administrator, Report to Congress, "Listing of Waste Oil as a Hazardous Waste, Section (8)(2), Public Law 96-463," January 16, 1981.

[45]Jacobs Engineering Company, for the U.S. Environmental Protection Agency, *Assessment of Hazardous Waste Practices in the Petroleum Refining Industry*, June 1976.

[46]Engineering Science, Incorporated, for the American Petroleum Institute, "The API 1976 Refinery Solid Waste Survey," March 1978.

[47]Pace Company, Inc., *Canadian Petroleum Refining Industry Waste Survey*, October 1980.

[48]Jacobs Engineering Company, op. cit.; Engineering Science, op. cit.

[49]Booz, Allen and Hamilton, Incorporated, and Putnam, Hayes and Bartlett, Incorporated, op. cit.

[50]*Illinois v. Gorsuch*, Civ. No. 78-1689; November 13, 1981.

[51]American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry, 1971-1980*, 1981.

[52]Battelle Columbus Laboratories, *The Cost of Environmental Regulations to the Petroleum Industry*, July 1980.

CHAPTER FOUR

STORAGE, TRANSPORTATION, AND MARKETING

INDUSTRY OPERATIONS

ENVIRONMENTAL CONSIDERATIONS

CHAPTER FOUR

STORAGE, TRANSPORTATION, AND MARKETING

INDUSTRY OPERATIONS

INTRODUCTION

As with any industry, petroleum raw materials must be transported to manufacturing centers and finished petroleum products distributed to consumers. At various points within this transportation and distribution system, storage must be provided for the raw materials (crude oil, natural gas, and natural gas liquids) and for the products. Since these storage, transportation, and marketing facilities have many technical and operating aspects in common, they have been grouped for this discussion of industry operations.

The scope of the network for petroleum storage, transportation, and marketing is illustrated by 1980 statistics showing that in the United States approximately 543,000 crude oil producing wells[1] fed 311 refineries,[2] which provided gasoline and oil to 15,000 terminals and bulk plants supplying 158,000 service stations[3] serving 122 million automobiles,[4] and provided many other products for home and industrial use. A summary of U.S. oil and gas transportation facilities is presented in Table 46.

Steel pipe is used to bring oil and gas from bearing rock to the surface, where they are separated. The gas is sent to a gas processing plant and is then routed into a natural gas distribution system that ultimately ends with the consumer. The water and sediment are removed from the crude oil and it is pumped through crude oil gathering lines and trunk lines to the refineries; pipelines then transport refined products from refineries to marketing distribution terminals, where short truck hauls deliver products to service stations and other consumers. In a similar manner, tankers and barges are used to transport crude oil to refining centers and, later, the refined product to marketing distribution points. Storage is required at many points along the system: at the crude oil fields, crude oil pipeline terminals, refineries, product pipeline terminals, and numerous marketing outlets such as bulk plants and service stations.

The arterial nature of the system that interconnects the many components of petroleum operations is beneficial to environmental protection. Within the United States, petroleum raw materials and products are handled almost exclusively in a closed system from source to customer. The same is particularly true for natural gas and liquefied petroleum gas (LPG). The volatility of these materials makes it necessary to handle them in a closed system under pressure, with little risk of their being discharged to the environment under normal operations.

Upsets do, however, occur. Wells develop line leaks; field gathering lines and pipelines develop leaks from corrosion, natural

TABLE 46

Oil and Gas Transportation Facilities

	Number of Units	Total Capacity
Gas Pipelines* (as of 12/31/77)	331,976 miles	NA
Petroleum Pipelines† (as of 12/31/78)	227,060 miles	NA
Tank Cars§ (as of 7/15/79)	107,552	2,175.5 MMgal¶
Tank Trucks§ (as of 12/31/79)	50,000	364.4 MMgal¶
Tank Barges§ (as of July 1979)	3,971	71.4 MMbbl**
Tank Ships§ (as of July 1979)	352	97.0 MMbbl**

*Includes gathering lines; excludes distribution lines.
†Includes gathering lines.
§Suitable for petroleum transportation.
¶MMgal = million gallons.
**MMbbl = million barrels.

SOURCE: National Petroleum Council, Petroleum Storage and Transportation Capacities, 1979.

phenomena, and from damage by construction and farm equipment; storage tanks develop leaks due to corrosion or settling; and tankers, barges, tank trucks, and rail tank cars become involved in accidents.

Petroleum industry equipment and systems are designed with substantial safety factors based on Department of Transportation (DOT) regulations, industry standards, and codes to minimize the potential impact of upsets. Standard operating procedures and training programs are used to prepare personnel for abnormal operations. Operating control systems are designed where possible to be fail safe and to remove the human error factor through automation and computer control. Upon failure of electric power, hydraulic oil pressure, instrument air, or steam, control valves throughout the system are designed to either fail open or closed, depending upon which condition provides maximum safety and the minimum upset. Such "designing out" of problems extends through the entire storage, transportation, and marketing segment of the industry, down to the automatic gas nozzle shutoff at the gasoline pump.

Communication and control systems have become increasingly sophisticated in the past 10 years. The miniaturization of computers, microprocessors, and programmable controllers enables the industry to rely on high levels of automation and "systems concepts" of monitoring and controlling operations from central locations. The operating requirements of storage facilities, pipelines, barges, tankers, rail tank cars, and even tank trucks, lend themselves to computer control. Reliable communication channels are established through telephone lines, microwave, and radio, often through communication satellites.

STORAGE

The petroleum industry requires storage facilities for tremendous volumes of raw materials and refined products. Tanks are required for crude oil and products; pressure vessels and underground storage are used for natural gas liquids; and underground reservoirs and cavities are used for natural gas. Primary storage is located at strategic points along the distribution system: at points of transfer between transportation modes, at points where a number of pipelines converge, and at manufacturing facility and distributor terminals. Secondary storage is maintained by small distributors of petroleum products further removed from the primary distribution system. Additional storage is maintained by consumers such as industries, the military, utilities, and homeowners.

Facilities can be divided into storage for liquid petroleum or natural gas, and further subdivided for discussion to above ground and below ground. Above-ground storage is used mostly for crude oil and refined petroleum products such as gasoline and distillates. Underground storage is most commonly used for storage of natural gas and LPG. Some requirements for primary storage of crude oil and refined product storage are illustrated below:

- To receive and hold large shipments, which are delivered in discrete parcels but are utilized continuously

- To accumulate quantities for tanker, barge, or pipeline movements

- To meet seasonal peaks in product demand; for example, allowing for accumulation of distillate fuel oil for winter consumption and of gasoline for summer consumption

- To segregate different grades and qualities of crude oils, unfinished oils, and finished products

- To accumulate products and crude oil before and during planned refinery maintenance periods

- To provide storage for contingencies to avoid operational interruptions.

U.S. stocks of crude oil and products (including strategic reserves) at the end of 1980 were about 1,395 million barrels, a 262 million barrel increase over the 1975 amount of 1,133 million barrels.[5] This volume of crude oil and product stocks represents only part of the total volume of tankage required during production, processing, transportation, and marketing. For a simplified diagram of the distinction between storage capacity and inventory, see Figure 56.

In 1978, the National Petroleum Council (NPC) surveyed the petroleum industry to determine the amount of primary storage capacity.[6] Table 47 summarizes the results of that survey.

The NPC also examined secondary and consumer storage capacity for gasoline and distillate fuel oil in the United States. This examination indicated that storage capacity exists for at least 500 million barrels, or more than 60 percent of the primary storage for these products.[7]

Underground storage capacity for LPG in the United States in late 1968 was 162 million barrels. Underground storage in 1979 was 411 million barrels, an increase of 249 million barrels. There were 315 underground reservoirs for natural gas in 1968, with capacity for 4.8 trillion cubic feet. By 1980, this storage capacity had increased to 412 underground storage reservoirs located in 26 states with a total capacity of 7.6 trillion cubic feet.[8]

Steel tanks have long been the principal form of petroleum storage. Storage technology has improved as the industry has searched for more economical, safer, and cleaner ways to store inventories of raw materials and products. Underground caverns, refrigerated storage, and improvements in design and construction of steel tanks have occurred.

Improvements in the design of floating roofs and secondary seals for open top tanks and in the development of internal floating roofs for fixed roof tanks have reduced storage evaporation losses, thus minimizing release of hydrocarbon vapors into the environment. The improvements also reduce the accumulation of rainwater in the product. Interior and exterior coatings are used to reduce corrosion and to protect the quality of sensitive products such as aviation jet fuel.

Volatile products, such as propane, propylene, and butane, are used as petrochemical feedstocks and by domestic consumers for home heating. Since propane, propylene, and butane have high vapor pressures at normal ambient temperatures, high-pressure storage vessels are required. Large steel tanks to safely contain these pressures [up to about 250 pounds per square inch gauge (psig)] are expensive. The safest and most economical storage method developed for these products (also the most commonly used) is to store propane and butane as liquids in large underground storage caverns, with as much as one million barrels of capacity. Most of these caverns have been formed by leaching of salt domes or by underground mining in limestone, shale, or granite formations.

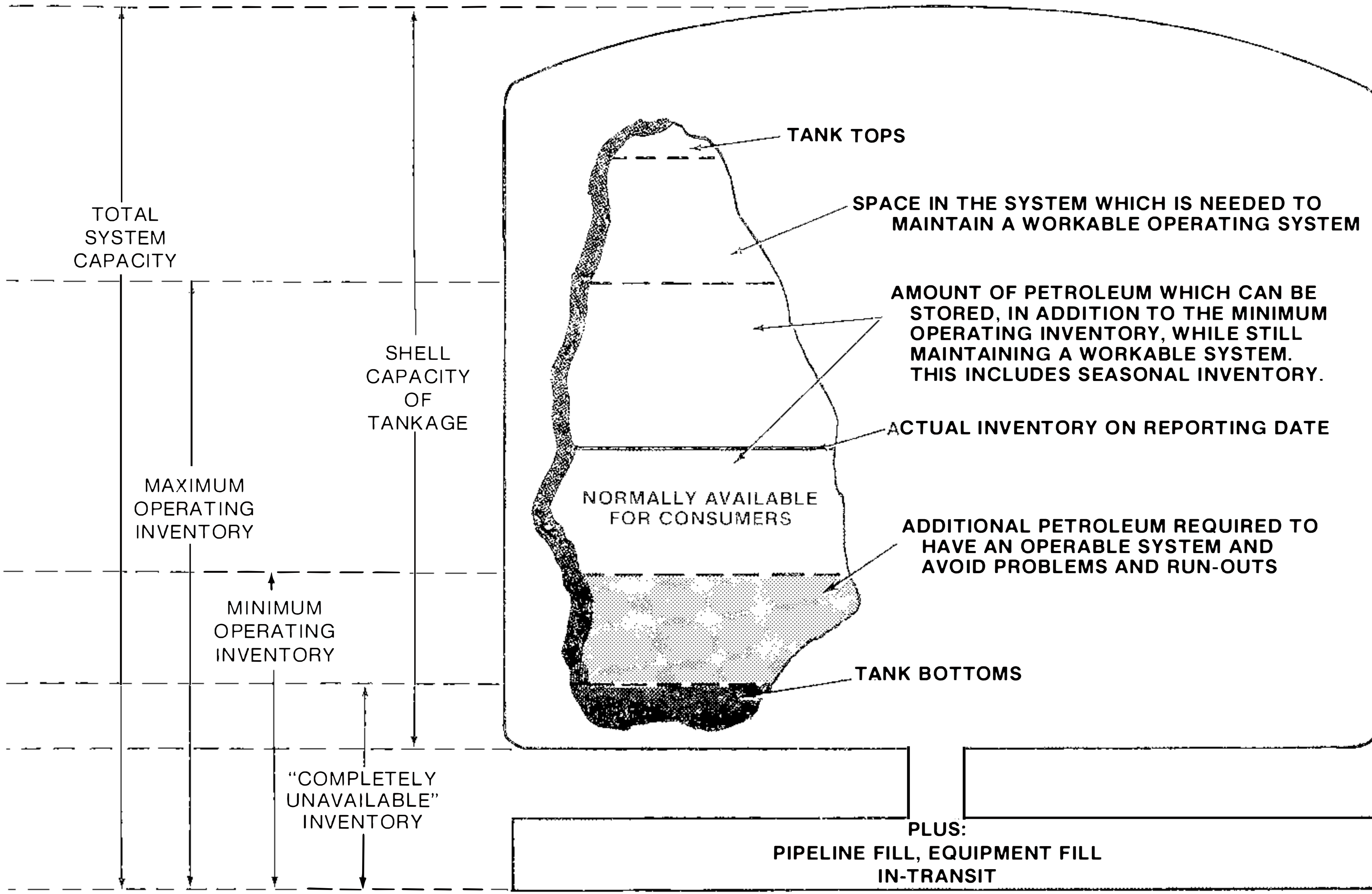


Figure 56. Simplified Diagram of Terms Describing Petroleum Inventories and Storage Capacities.

SOURCE: National Petroleum Council, *Petroleum Storage and Transportation Capacities*, 1979.

TABLE 47

U.S. Primary Distribution System
Total Shell Capacity of Tankage
September 30, 1978
(Millions of Barrels)

Crude Oil	462
Gasoline	438
Kerosine	90
Distillate Fuel Oil	365
Residual Fuel Oil	162
Total	1,517

SOURCE: National Petroleum Council, *Petroleum Storage and Transportation Capacities*, 1979.

Another method of storing highly volatile products, like propane and butane and liquefied natural gas (LNG), is to cool them sufficiently so they are liquid at atmospheric pressure. Low-pressure, refrigerated vessels are used, but are expensive to construct and operate.

Underground natural gas storage involves transporting gas from producing fields and reinjecting it into other reservoirs where it is stored until needed to supplement other natural gas supplies in meeting market requirements. Traditionally, these underground storage reservoirs have been located near areas of consumption, but in some cases reservoirs are being developed in the producing areas. In 1980, approximately 10 percent of the natural gas consumed in the United States was withdrawn from underground gas storage.[9]

The principal functions of underground gas storage are to meet the peak demands of the winter season and to provide off-peak storage for pipeline gas during the warm summer months. Underground storage played a particularly important role in meeting the nation's energy needs during the unusually severe winter of 1976-1977. By the end of that winter season, nearly 72 percent of the available volume had been withdrawn for consumer use. Because underground storage permits greater utilization of pipeline facilities (near 100 percent load factor) and more efficient gas deliveries to the market, it is an important factor in conservation and the development of new markets.

Natural gas is stored in three types of storage pools. The oldest type of storage reservoir is a depleted gas or oil field. In some states, because of a lack of depleted gas and oil reservoirs, natural gas has been stored in water-bearing sands (aquifers) that never contained hydrocarbons. In recent years, salt cavities have been used to store natural gas.

I. Offshore Storage

In recent years, platform technology has permitted the conduct of offshore oil and gas exploration and development further from land. In most offshore areas of the United States, oil and gas production is generally delivered to shore by pipeline. In the early years of domestic offshore development, storage of oil at offshore locations and barging to onshore terminals was attempted. Interruptions in deliveries as a result of bad weather conditions, especially during winter months, have caused this system to become less favored than the pipeline system. There remain, however, a few fields where the isolated location, small quantity of production, or other circumstances may dictate offshore storage for economic or other reasons. It is conceivable that as exploration and development proceed farther from shore, economics could dictate the use of offshore storage facilities of a type that are prevalent in foreign operations. Any vast offshore storage facility certainly is a potential pollution source; however, with proper equipment and operating procedures the risk of pollution is minimal.

The petroleum industry is seeking a more economical means of temporarily storing crude oil while awaiting marine transportation to refineries. At the present time, offshore storage facilities are being installed and operated in water depths up to 500 feet. It is expected that in the near future offshore storage and crude oil transfer facilities will be required in much deeper waters. The size requirement for an offshore storage unit depends upon both the lease production rate and the availability of marine transportation to unload the storage tanks periodically. A storage capacity equal to approximately 10 days of production is accepted as a minimum standard. Offshore storage varies in capacity from 10,000 barrels to approximately 1.5 million barrels.

Offshore crude oil storage facilities may be grouped into the six broad categories discussed below. Each classification describes the storage units in terms of the position of the primary tankage with respect to the surface of the water. They are:

- Elevated or above-surface storage
- Floating storage
- Semisubmerged storage
- Submerged storage -- moored
- Submerged storage -- bottom-supported
- Combination storage -- submerged and elevated.

A. Elevated or Above-Surface Storage

Elevated or above-surface storage is located on a platform above the surface of the water. Extensive use is made of special tanks placed on the decks of offshore production platforms. This

type of storage frequently shares a platform with gas-separating and other production facilities. Structural capabilities of platforms used in the Gulf of Mexico normally limit on-deck storage to 10,000 barrels.

B. Floating Storage

Floating storage applies to vessels such as barges, tankers, and those tanks having a high positive buoyancy. Barges are frequently used in shuttle service during the early development phase of an offshore field. One barge receives oil at a production platform, while others are in transit between the shore terminal and platform. Several floating storage systems have used marine tankers of various sizes up to 250,000 deadweight tons (DWT) to receive and store oil directly from producing wells; the oil was in turn off-loaded into another tanker for transportation to distant ports. Specifically built storage barges capable of holding one million barrels of oil and having auxiliary oil treating and pumping facilities on board are also being used. Figure 57 illustrates this type of storage.

C. Semisubmerged Storage

Semisubmerged storage applies to tanks moored in places that have a low positive buoyancy and float with only a very small fraction of their volume above the surface. The semisubmersible drilling platform-type structure lends itself to this use. Generally, this type of storage has been used in protected waters. See Figure 58 for a specific example of this type of structure.

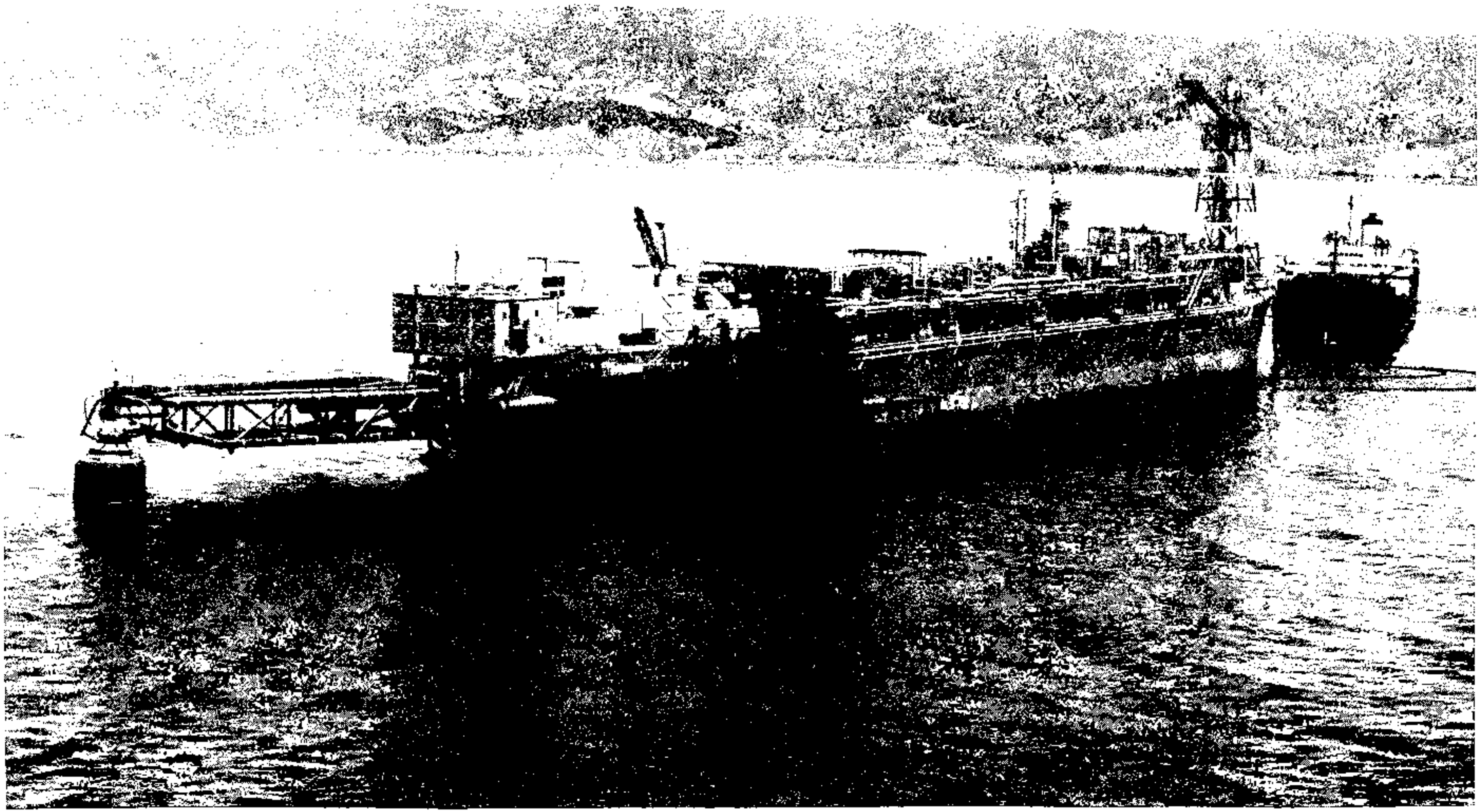
D. Submerged Storage -- Moored

Submerged storage units may be either fully enclosed or bottomless. They have a low positive buoyancy and are normally moored at some point below wave action. They may be at or near the ocean floor (see Figure 59).

E. Submerged Storage -- Bottom Supported

A bottom-supported submerged storage tank has a negative buoyancy and rests on the bottom without the aid of mooring lines. It may be either fully enclosed or bottomless. It may be attached to the bottom with piling to increase its resistance to drag by the current. The storage tank is frequently equipped with an above-water structure, which supports production, loading, and submerged tankage control facilities. The above-water structure offers minor exposure to storm and collision (see Figure 60).

An example of sea-floor storage is the 500,000-barrel bottomless conical tank named "Khazzan Dubai I," installed by the Dubai Petroleum Company in the Persian Gulf off of Dubai. It is permanently anchored to the bottom with piles. It converges upward to a relatively small neck projecting above the water, carrying the switching and control equipment. Figure 61 illustrates this type of storage.



SOURCE: IMODCO.

Figure 57. Floating Storage—Moored Storage Tanker.

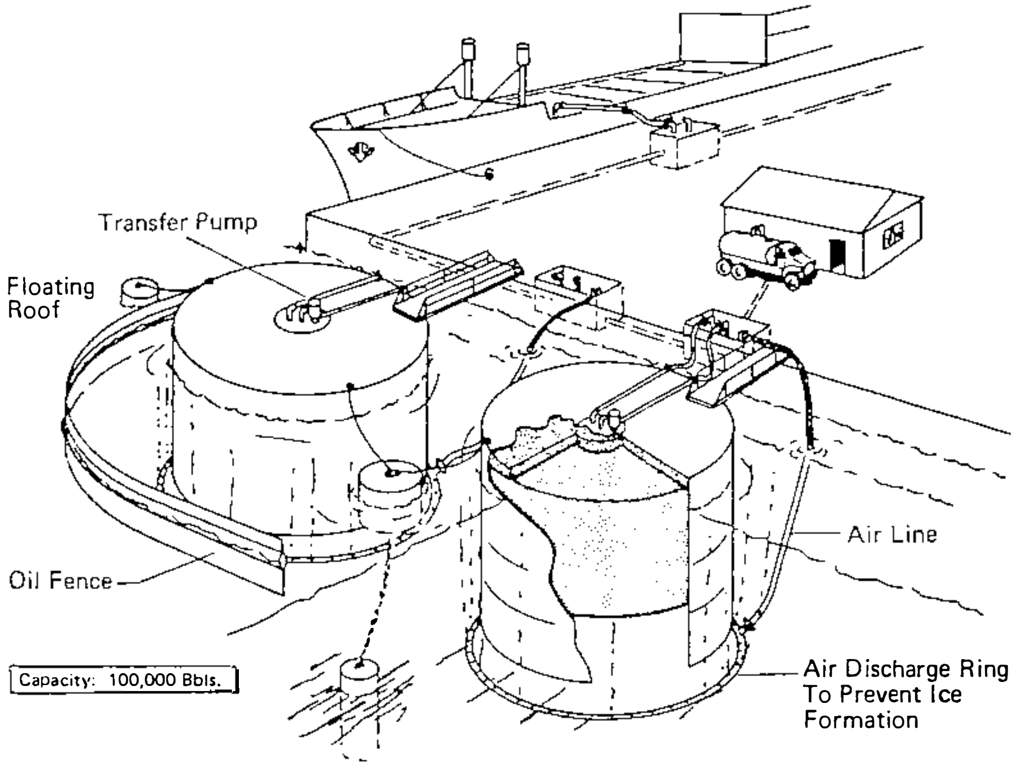


Figure 58. Semisubmerged Storage.

F. Combination Storage -- Submerged and Elevated

The principal storage unit in a combination storage facility is the submerged tank. The elevated tank normally has from 10 to 30 percent of the submerged capacity, and its primary purpose is to replace the subsurface ballast required in the conventional submerged facility to achieve an overall negative buoyancy (see Figure 62).

The submerged storage facility is most applicable in deep waters, is competitive with subsea pipelines when offshore production is at long distances from shore, and its large capacities are an advantage when the oil produced is destined for distant refineries via supertankers.

II. Automation and Safety

Automatic and remote supervisory control systems have become necessary as costs of raw materials and manpower escalate and as goals for increasing levels of operating safety are met. Large refinery tank farms and storage terminals require many men to gauge tanks and to operate valves and pumps without the availability of automatic and remote supervisory control.

Supervisory control systems with uninterrupted computer monitoring and surveillance allow remote gauging of tank levels and

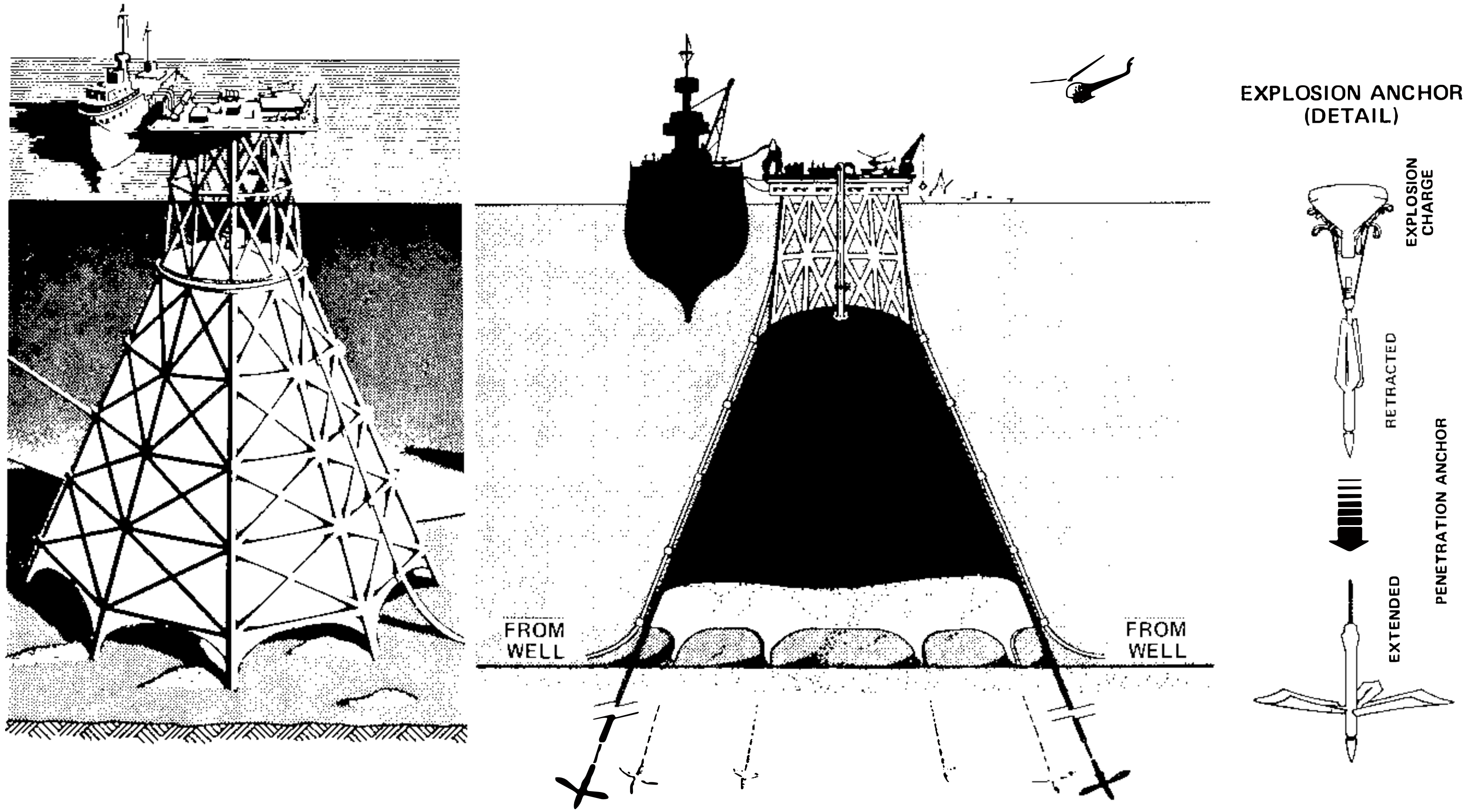


Figure 59. Submerged Storage—Moored.

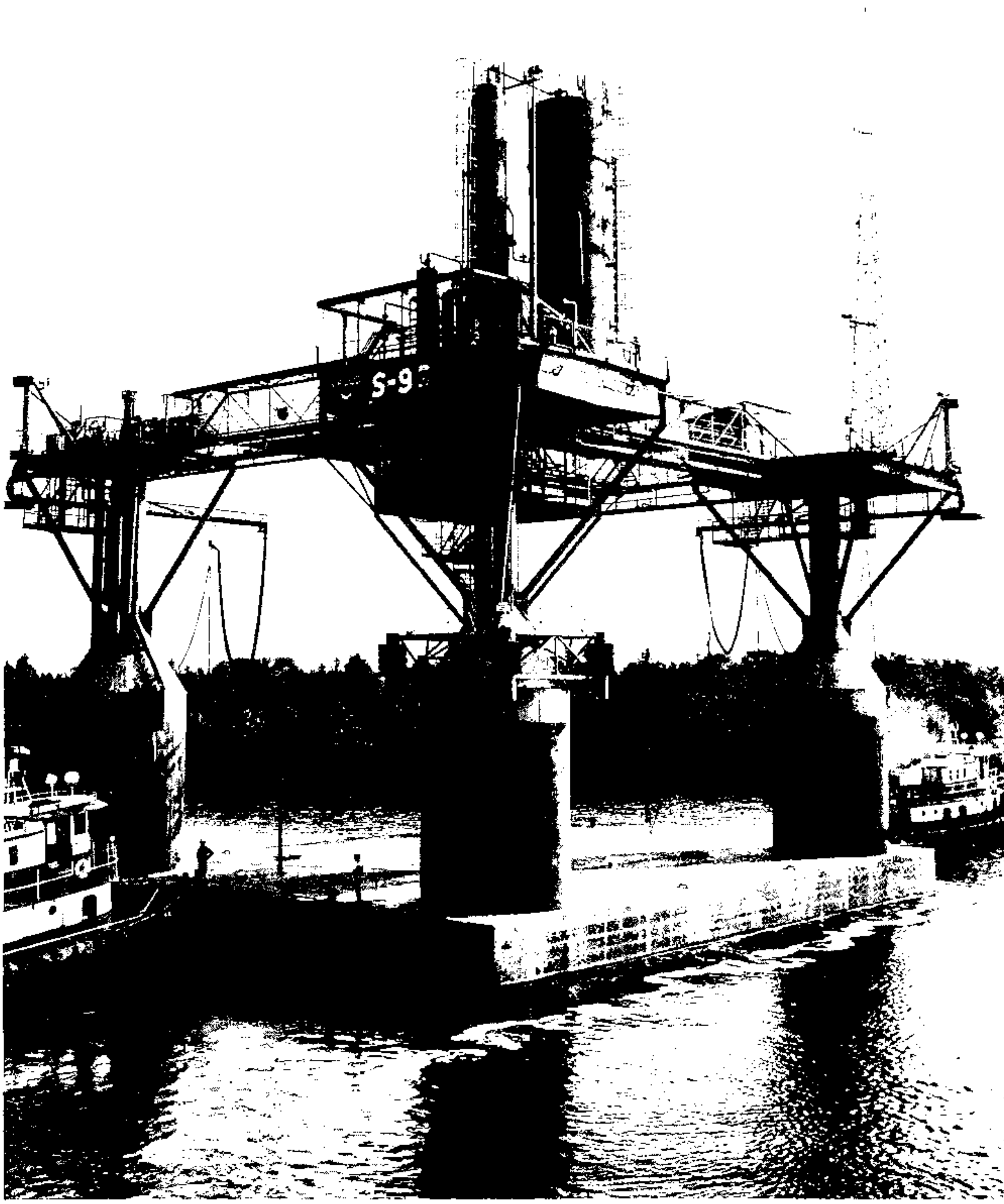


Figure 60. Submerged Storage—Bottom Supported (Above- and Below-Water Structure).

SOURCE: Bethlehem Steel Corporation.

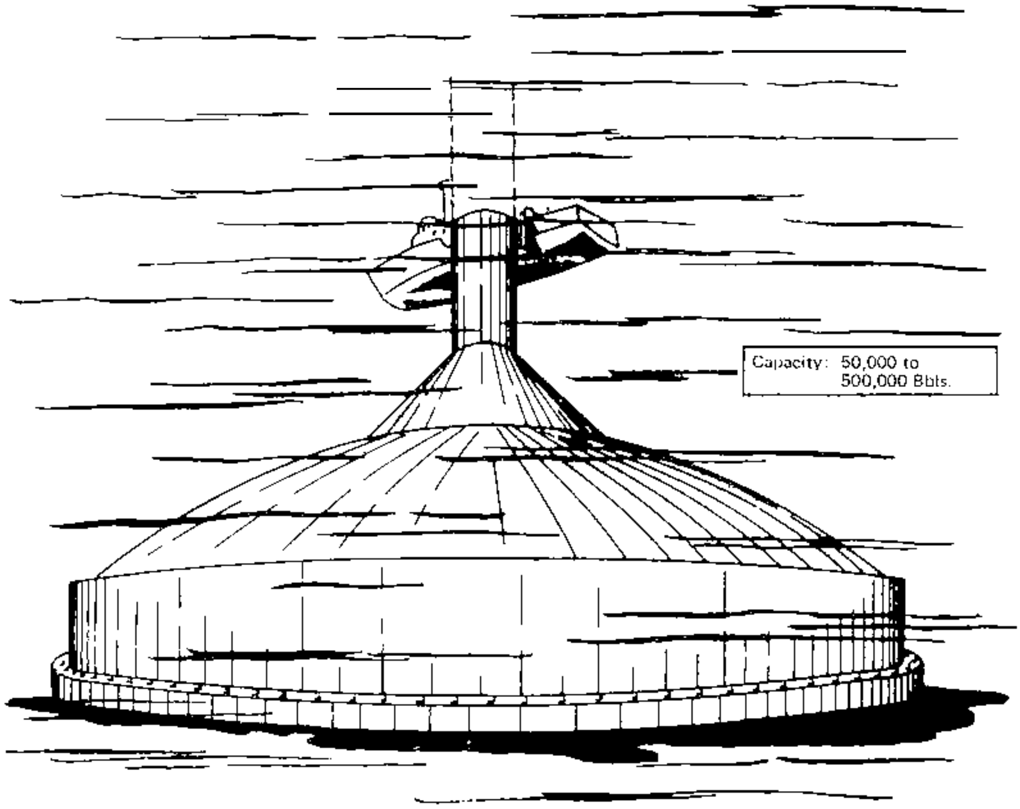


Figure 61. Submerged Storage—Bottom Supported (Sea-Floor Storage).

remote valve and pump operation with automatic switching and shutdown of operations if operational upsets occur. Routine monitoring of operation conditions, such as flow rates, pressures, temperatures, tank levels, and operating unit alarm status, is a typical capability of a Supervisory Control System. Such systems are invaluable in preventing tank overflows, preventing crude oil and product contamination, reporting and preventing unauthorized operations, and providing a written log of operating conditions.

TRANSPORTATION

I. The Petroleum Distribution System

A. Introduction

The system of pipelines, tankers, barges, tank cars, and tank trucks that moves crude oil from producing areas to refining centers, and the similar modes of transportation that move refined products from refining centers to marketing areas, are generally categorized as the primary petroleum distribution system (Figures 63 and 64). Considerable tankage must be provided within this transportation network in order to maintain normal flexibility for the overall operation of the supply system. The petroleum distribution system also includes the secondary distribution system and the consuming sector, which contain substantial capacity and tankage.

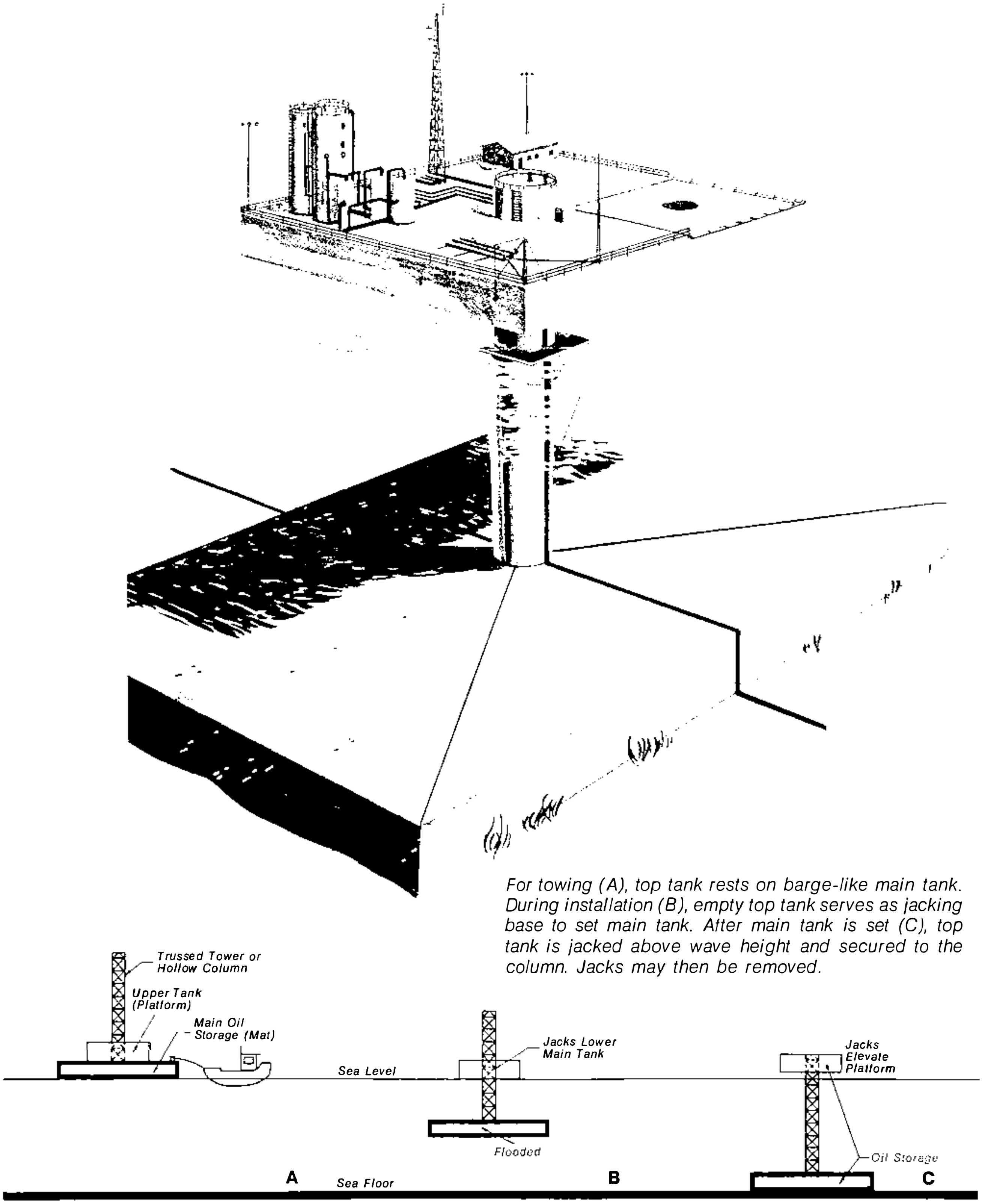


Figure 62. Combination Submerged and Elevated Storage.

SOURCE: Bethlehem Steel Corporation.

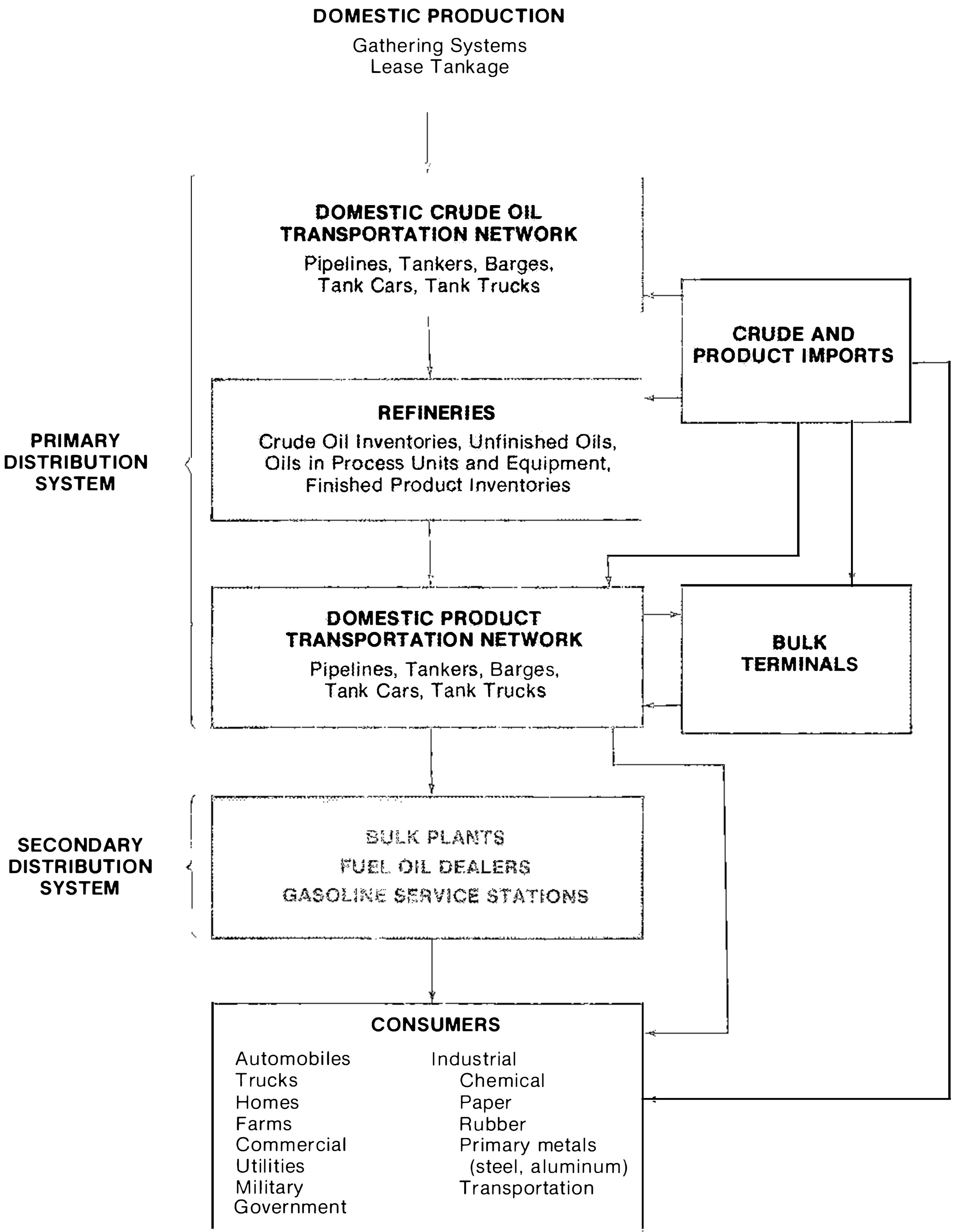


Figure 63. The Petroleum Distribution System.

SOURCE: National Petroleum Council, *Petroleum Storage and Transportation Capacities*, 1979.

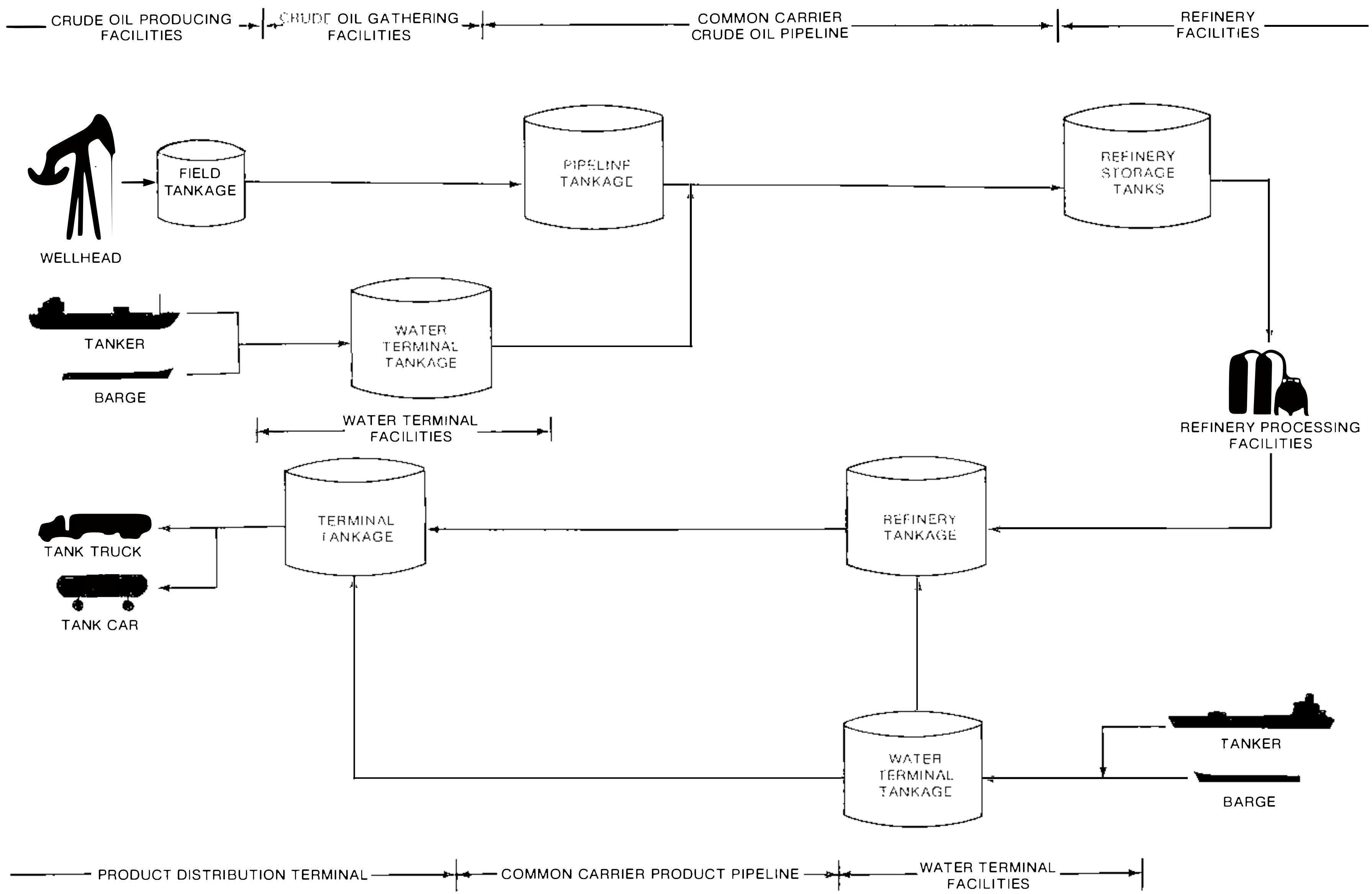


Figure 64. Simplified Crude Oil and Refined Products Flow Chart.

SOURCE: National Petroleum Council, *Petroleum Storage and Transportation Capacities,* 1979.

1. Primary Crude Oil Distribution System

Primary crude oil trunk pipelines are comparable to the long lines systems in communications or to the main lines of railroads. These trunklines are served by gathering systems in producing areas that pick up crude oil from numerous oil fields as well as from marine unloading terminals.

Trunk pipelines, the principal mode of crude oil transportation, are generally routed through focal points, or hubs, where a number of pipelines converge. These hubs are comparable to locations on a railroad freight interchange system. At such points, transfers to carriers destined elsewhere may be implemented. Examples of such locations are: Midland and Odessa in western Texas; Longview in eastern Texas; Cushing, Oklahoma; Fort Laramie and Guernsey, Wyoming; and Patoka, Illinois. A large amount of storage capacity is required at these points, not only to enable the oil to be brought into the area from numerous producing regions, but also to provide the tankage for segregation, batching, and inventorying necessary for continuous pipeline operation before the oil can be moved to refineries.

2. Primary Products Distribution System

The primary products distribution system is composed of the products pipelines, tank cars, and tank trucks that move products overland and the barges and tankers that provide waterborne movements. While products are still in refinery tanks there is usually a choice as to the direction in which the products may move, along with a choice of the mode of transportation. Once a product is on its way in an element of the primary distribution system, it is generally committed to the geographic area that is serviced by that particular element.

For example, the Colonial Pipeline extends from the Houston-Beaumont, Texas, area to New York Harbor, and passes through Baton Rouge, Atlanta, Greensboro, Richmond, Washington, D.C., Baltimore, and Philadelphia. The product in the primary distribution system can be sold or exchanged by the shipper at any point or diverted by the shipper to any delivery point along its geographic route. When the product is delivered out of the pipeline into a bulk terminal tank along the route, it leaves the primary system and enters the secondary system, and the ability to divert that product to a different geographic location becomes even more limited.

3. Secondary Distribution System

Petroleum products leave the primary distribution system either for further distribution through the secondary system or for direct sale to consumers. This secondary system includes small resellers of petroleum products (jobbers), such as bulk plants, gasoline service stations, or fuel oil dealers. Deliveries are generally made by tank truck. The secondary distribution system also holds a considerable amount of inventory and tank capacity.

Consumers of petroleum products include individuals who buy gasoline for their cars and distillate fuel oil to heat their homes. Among other consumers of petroleum products are the agricultural industry, utilities, large and small manufacturing industries, and transportation companies. Almost all consumers have their own storage facilities for the products they consume.

B. Petroleum Pipelines

Petroleum pipelines normally carry either crude oil or petroleum products, although some pipelines carry both. These pipelines and facilities are designed, constructed, tested, operated, and maintained in accordance with DOT regulations, which are largely based on codes and standards developed and published by the organizations listed below:

- American Petroleum Institute
- American Society of Mechanical Engineers
- Manufacturers Standardization Society
- American National Standards Institute
- American Society for Testing and Materials
- National Fire Prevention Association
- National Association of Corrosion Engineers.

State and local regulatory agencies may have applicable regulations, which in some instances can be more stringent.

Domestic crude oil is moved by pipeline from producing oil fields to refineries (often from thousands of oil wells through smaller gathering lines and main lines) and imported crude oil is moved by pipeline from ports to refineries. Petroleum product pipelines move refined products from refineries to terminals from which distributors move it to the market.

Crude oil and petroleum products are pumped through pipelines in a continuous flow, propelled by various types of pumping equipment. Pipelines are connected to storage facilities called tank farms at their origin and delivery points, and sometimes to tanks at intermediate points. All petroleum entering or leaving the system is measured to account for any differences between receipts into the pipeline and deliveries out of the pipeline.

1. Route Selection

A major part of planning a new pipeline is route selection. The key considerations for routing are the origin, destination, and intermediate delivery points. Product pipelines typically have a number of intermediate delivery points because product demand tends to be distributed with population; crude oil pipelines normally

have only a few intermediate delivery points, which are determined by refinery locations or by pipeline distribution centers.

Another consideration is topography. High terrain generally means higher construction and pumping costs; it takes more power to pump petroleum uphill than it does to pump it along flat terrain. River crossings are more expensive to construct because of burial requirements caused by factors such as shifting currents, flood plains, and course changes. Where possible, urban areas and river crossings are avoided because of higher construction costs. The pipeline company must obtain right-of-way for the route either by purchase of land or purchase or lease of right-of-way from the land owners.

Permits are required from various agencies of federal, state, and local governments. The precise requirements vary, but government permits for most projects now require a minimum of two to three years for processing. The routes of most major pipelines proposed in the last several years have met with some environmental objections. The pipeline company may answer the objections satisfactorily or change construction or routing plans to resolve the objection. If resolution is not possible, the pipeline construction plans may be cancelled or suspended.

2. Construction

Pipelines are usually constructed by specialized pipeline contractors. First, the pipeline's right-of-way is cleared to accommodate construction equipment. Pipe sections, often 40 to 80 feet in length, are placed (or "strung") along the cleared right-of-way, and the ditch is excavated. Where necessary, the pipe is bent to fit the ditch, welded either manually or automatically; cleaned, wrapped, or otherwise corrosion protected; and lowered into the ditch. Welded joints are visually inspected and many are examined by radiography to detect flaws. Any flaw requires either repair or removal of the weld and welding the joint again.

Many improvements have been and are being made in pipeline construction technology. An example of the application of this technology is the Trans-Alaska Pipeline System (TAPS), which now carries 1,520 thousand barrels per day (MB/D) of crude oil across the Alaskan wilderness.

3. Materials and Equipment

In the past decade many advances have been made in the materials used in pipelines. In turn, these new materials have caused the development of new construction equipment and techniques. For example, the yield strength of pipe steel has risen steadily, thus permitting the use of thinner yet stronger pipe walls. Pipe today has a yield strength of up to 70,000 pounds per square inch (psi), an increase of 25 to 35 percent over steels used 10 years ago. At the same time, new alloys have improved the ductile characteristics and the low-temperature properties of the pipe. These developments have improved service over a wide range of conditions, resulting in significantly lower construction costs.

Automated pipe welding techniques are common today. New welding rods with high tensile strengths and special properties that minimize the cracking of high yield strength weld metal have been developed for use with new steels and alloys. New welding processes have been developed, permitting faster construction and higher quality welding.

New materials and processes for coating both the outside and inside of pipe have been developed. In the past, external coatings were usually made from layers of asphalt or coal tar, enamel, felt, woven glass fibers, or paper. Recently there has been increased use of plastic tape, extruded plastics, and fusion-bonded epoxy thin-film coatings to coat the outside of pipelines. Fusion-bonded epoxy thin films are also available for inside coating.

Engines, motors, and pumps used on pipelines have not changed drastically in recent years, but improvements are constantly being made. More efficient yet smaller electric motors to drive pipeline pumps result in reduced costs and space savings. Low-speed industrial and high-speed aircraft turbines are also used to drive pipeline pumps. Where electrical power is inaccessible or very expensive, turbines can be fueled by gas or a small portion of the petroleum being pumped. TAPS has several small topping plants along its route that take crude oil from the pipeline, produce a diesel fuel product to supply the pipeline's turbines, and return the unused portion of the crude oil to the pipeline, where it is mixed with the passing crude oil.

Electronic, pneumatic, and hydraulic equipment for remotely controlling and monitoring pipelines has changed substantially. Computerized supervisory systems and solid state electronics have resulted in more efficient centralized pipeline operations. One or more pipeline systems can now be monitored from a computerized control center, requiring fewer people and providing substantially more data than previous systems.

4. Operations

A pipeline can be a single line of uniform diameter pumping at a uniform rate from one place to another, or it can be a substantially more complex system. The line can have intermediate entry and exit points, change diameters or pumping capabilities at various points, or be several separate pipelines running side by side with varying diameters -- the combinations are almost limitless. The typical pipeline will have origin and delivery points, breakout tankage, and a decreasing or increasing capacity as the line approaches its terminus. All of these factors make scheduling pipeline movements and overseeing pipeline operations a difficult and complex task.

The volume of liquid a pipeline can carry depends upon the size of the pipeline, the capabilities of its pumps and drivers, the specific gravity and viscosity of the liquid being pumped, and the topography of the pipeline route. Common carrier pipelines publish tariffs that establish the price for shipping through them, and

state the conditions and specifications of what may be shipped. A pipeline may set specifications on the pour point of the liquid (the maximum temperature at which the liquid will no longer flow) and its viscosity (a measure of the resistance to flow exhibited by the liquid) because the rate of flow of a pipeline is determined by the slowest moving liquid in the pipeline. In addition, crude oil pipelines usually have specifications on the sulfur content, water content, gravity, and other properties of the crude oil that they will ship; product pipelines also may have limited capability to handle certain products. The reasons for establishing specifications on materials handled in crude oil and product pipelines are the need to maintain the rate of flow at an optimum level and the desire to avoid downgrading or contaminating the crude oil or products normally shipped.

Because contamination results in cost penalties to the shipper and/or the pipeline, pipelines protect crude oil and product qualities by means of careful quality control practices. Separation of different grades of crude oil or petroleum products in a pipeline is called batching. To minimize contamination, batches are sometimes physically separated by batching devices such as elastic spheres. Even if batching devices are used, some mixing, or interface, occurs. To minimize this interface and maximize the uncontaminated crude oil or product, shipments are batched in a continuous, orderly sequence with shipments of similar quality. Crude oil is normally batched by sequencing compatible crude oils considering such qualities as specific gravity, viscosity, sulfur content, and whether the crude oil is asphaltic, paraffinic, or naphthenic based. Products are typically shipped in groups that move from lighter to heavier gravities and then back to lighter again in sequences such as this: gasoline-kerosine-fuel oil, fuel oil-kerosine-gasoline. This sequence of product is normally moved in regular, repetitive cycles that are usually 10 days in length, with three cycles per month and 36 cycles per year. Cycles may vary depending on the pipeline capacity, scheduling of refinery operations, and market demand.

In a segregated pipeline, specific shipments are identified as the property of a shipper and are moved through the pipeline in such a way as to maintain the integrity and identity of the specific product. In a fungible products pipeline, the pipeline company sets a range of specifications for each grade of fungible product. All volume of that product grade is commingled or mixed into a single batch. When the fungible batch reaches the delivery point, every shipper receives his appropriate volume. The shipper can receive another shipper's original product rather than his own with the realization that the product received meets the specifications required. In a common stream crude oil pipeline, the crude oil the shipper receives may vary from that which the shipper put into the pipeline. Sometimes the shipper will pay or receive a price differential based on the quality difference between the oil delivered into the line and the oil received, but usually he will simply take the crude oil, provided that it is either all sweet crude oil (less than 0.5 weight percent sulfur) or all sour crude oil (greater than 0.5 weight percent sulfur). When large differences exist in the

quality of crude oil injected into a pipeline, a gravity-sulfur bank may be established to compensate the shipper for the differences in the quality of crude oil delivered and received.

Efficient pipeline operations depend on large shipments, which result in lower operating costs for the pipeline, and consequently lower transportation costs to shippers. Pipelines normally have minimum batch sizes ranging upward from 25,000 barrels. Minimum batch requirements are often established for operating reasons and for maintaining product integrity. The purpose of establishing minimum batches is to keep the interfaces small in relation to the size of the shipment and thus minimize losses.

Individuals or companies that need to ship crude oil or products on a common carrier pipeline may do so if they meet the requirements of the pipeline's published tariffs and ask for, or nominate, shipment on the pipeline during the coming month by informing the pipeline what and when they want to ship. If they meet the published rules and regulations of the pipeline's tariff (which is filed with the Federal Energy Regulatory Commission), the pipeline confirms the movement and a shipment date. After the batch has been delivered to the shipper or to a connecting pipeline, the shipper is billed for the movement at the rate published in the tariff.

If the requests for shipments during a given month are greater than the capacity available, a pipeline may have to prorate available capacity among all those nominating for it. Because of the increasing demand for pipeline transportation, a few pipelines in the United States have had to prorate capacity among shippers. Pipelines generally have formulas for computing prorations in order to treat shippers on a fair and equitable basis.

The physical characteristics of pipeline operations require a pipeline to be full before any deliveries can be made. This line fill is normally furnished and owned by all of the shippers on a pipeline but remains in the custody of the pipeline company. It includes pipeline fill, manifolding and tank line fill, and working storage fill. Line fill can be as much as several million barrels.

Scheduling shipments through a pipeline is a complex and exacting job. The pipeline companies must balance all the various nominations of different qualities of crude oil or grades of products, their entry points and destinations, and their shipment and arrival dates. Many pipeline companies use computers to prepare and adjust short- and long-range schedules and update them on a regular basis. Schedule changes often occur on both a short- and a long-range basis, and shipment dates must be shifted from week to week and day to day. These changes are caused by refinery shutdowns, pipeline operating problems, erratic tanker arrivals, and volume changes by shippers. In addition, pipeline schedules vary seasonally as product demand changes.

Pipeline operations are monitored around the clock from a central location by dispatching personnel, many using supervisory control equipment (see Figure 65). Dispatchers control operations at

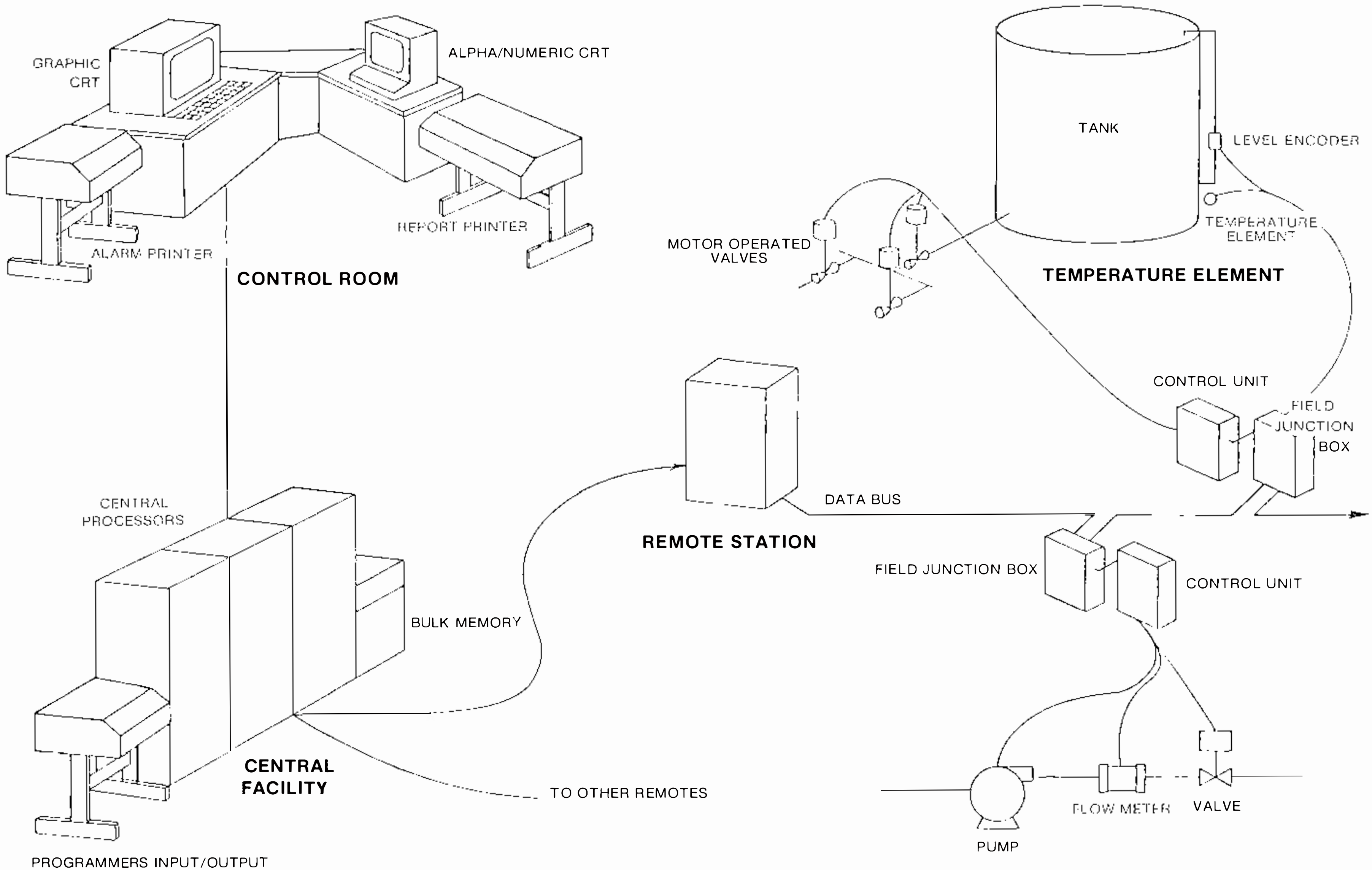


Figure 65. Pipeline Supervisory Control Schematic.

SOURCE: Houston Engineering Research Corporation.

remote, unmanned facilities; keep track of the grade, quantity, and ownership of each batch; coordinate with field operation personnel at manned facilities; and monitor flow rates, pressures, and shipments to maintain safe and efficient operations.

When trouble occurs, such as a sudden increase or drop in pressure, alarm systems alert the operator and may begin a programmed shutdown of operations. The industry is working to perfect more sensitive and reliable devices to measure flow into and out of the line. Automatic computer comparison of these measurements, which compensate for changes in gravity, viscosity, pressure, and temperature, will indicate if some oil has been lost along the way.

Although this view of pipeline operations indicates how complex the operation of a pipeline can be, it has only considered the operation of a single pipeline or pipeline system. In practice, a shipment of crude oil or product may change systems several times before it is delivered to its final destination. For example, crude oil from southeastern Utah can move through the Texas-New Mexico Basin, Cushing to Chicago, Texaco-Cities Service, Lakehead, and Interprovincial Systems to the Buffalo, New York, refineries; or products can move from Lake Charles, Louisiana, to Pittsburgh, Pennsylvania, through either the Colonial and Laurel Systems or the Explorer, Arco, and Buckeye Systems to product distribution terminals. These shipments may be shipped on pipelines with varying quality requirements or may be moved through several different storage facilities between pipelines; however, they will meet the shipper's quality specifications at their destination.

5. Integrity and Maintenance

Improvements in pipeline integrity and maintenance have dramatically reduced the number of pipeline leaks or accidents. These improvements are a result of many factors, the most important of which are:

- Material quality
- Welding techniques
- Coatings
- Testing
- Inspections
- Cathodic protection.

Of primary importance is the high-grade steel used to manufacture the pipe. A critical job on the construction site is welding the pipe together. Only highly qualified and tested welders are used, and their work is kept under continuous close inspection, both visually and radiographically. Proper welds are actually stronger than the pipe itself. Before the line is lowered into the ditch, the outside of the pipe is covered with protective coating.

Before the line is put into operation, it is tested by filling segments with liquid (usually water) and raising the pressure to exceed the highest stress level expected during normal operations. This hydrostatic test is continued for a prescribed time in accordance with DOT regulations. For continuing protection against external corrosion, a low voltage direct current is applied to the pipe to counteract the natural pipe-to-ground corrosion-causing currents that can eventually result in leaks. Where necessary, corrosion inhibitors are injected into the pipeline stream during operation to protect against internal corrosion.

Pipeline maintenance is continuous and involves routine maintenance of the pipeline's pump stations and rights-of-way. Equipment, pump stations, and tank farms require repair, replacement, and/or recalibration. Many pipeline companies have maintenance crews to repair leaks, while others have contract personnel available on short notice. Some pipeline companies perform major maintenance with company personnel, such as line lowering or relocation, while others contract out major maintenance. However, all companies use their employees to supervise and inspect the work performed by others.

Pipelines are cleaned internally of dirt, sediment, wax, and other matter by use of scrapers, or "pigs," which can be either cylindrically shaped metal devices with knives and/or wire brushes, or polyurethane devices of various shapes. They are put into and taken out of the pipeline through pipe and valve assemblies called scraper traps. These scrapers are propelled by the oil in the pipeline at the line flow rate and push the dirt or wax into the scraper trap where it is removed.

Many problems along the pipeline can be located and identified by computers at the pipeline's control center. Small leaks that might not result in readily identifiable drops in line pressure are typically located by aircraft patrols. All main lines are inspected at least once every two weeks and in many cases more frequently, usually by aerial patrol, to check the pipeline route for abnormal conditions such as washouts, new excavations on or near a pipeline, other construction, and soil discoloration from leaks.

When necessary, maintenance crews are dispatched to locate leaks and repair or replace the section of pipe involved. Once a leak is located, the repair crews uncover the line and place a specially designed clamp around the pipe and over the leak to stop it. After the flow is stopped, one of several methods may be used to repair the line: in the case of a very small leak a full encirclement sleeve is welded to the pipe; for larger leaks the line is shut down and drained, the damaged section is removed, and a new section welded in place. All new welds are tested and the pipe is coated to prevent corrosion.

Many damaging pipeline contacts occur during the digging of ditches or pits, and the grading of roads or land by construction equipment operated by non-industry personnel. To help protect pipelines from external sources of damage, pipelines are clearly

marked above ground where they cross roads, highways, railroads, property lines, and rivers. Most pipelines are routed wherever possible and practical so as to avoid congested residential and industrial areas. In these areas, pipelines are provided extra cover to avoid potential damage from construction equipment. The "one call notification system" is increasingly being used to protect pipelines from new construction damage (see the Water and Land section of this chapter).

6. Offshore Pipelines -- Systems and Procedures

The use of long and large submarine pipelines at considerable depths is common practice, and the offshore operating environment requires innovative use of engineering techniques.

The size of offshore pipelines depends upon their use, throughput, and purpose. Flow and control lines between producing wells and gathering lines require pipe size from 2 to 8 inches in diameter and are generally of relatively short length. Gathering lines, which move the oil to central process and pumping stations, are typically 4 to 12 inches in diameter and are usually less than 50 miles in length. Transmission lines of 20- to 48-inch diameters are widely used and lengths in excess of 50 miles are relatively common, with a few 200-mile subsea pipelines in service. Pipelines with capacities of 250 to 1,000 MB/D are currently in use. Throughputs as high as 2 million barrels per day (MMB/D) are planned for the larger (48-inch diameter) lines.

Methods for joining lengths of pipe are many, but welding is the most popular and the least likely to develop leaks. Other means have been used, however, including threaded couplings, flanges, and numerous special couplings.

The principal way to fabricate a pipeline is to weld it together joint by joint. This technique is the heart of the lay barge operation. The pipeline is fabricated by adding one joint of pipe at a time and moving the barge forward in even steps to pass the joint through a series of welding and inspection stations along the assemblyway until the joining process is complete. The forward movement of the barge passes the joint through the radiographic inspection, joint coating, and other stations along the launchway as required to complete its integration into the pipeline. Precoating of the pipe for corrosion protection is normal, and if weight coating for negative buoyancy is necessary, this process is completed well in advance of the laying process.

In some areas, pipelines are laid under the sea bottom in trenches to protect them from currents and other external damage forces. Specially equipped barges are used to lay the line. The line must be leakproof against both internal and external pressures. The structural strength must be sufficient to resist wave and current forces, and the pipeline itself must be able to withstand stresses during laying and stresses due to irregularity of the particular sea bottom.

Care must be taken to prevent faulty construction practices that result in damage to the pipe itself. Experience indicates that girth weld failure is not a significant problem, and those failures that have occurred are in such welds that have usually been made by earlier techniques. After the pipe has been put in service, failures can result in pollution incidents. Perhaps the most critical phase of the construction process is the handling of pipe to avoid stresses beyond its minimum yield strength.

Two basic construction systems are in use today. The most common involves a structure, commonly called a stinger, that supports the pipe throughout part of its length from the laying barge or platform to the ocean bottom (see Figure 66). With proper care,

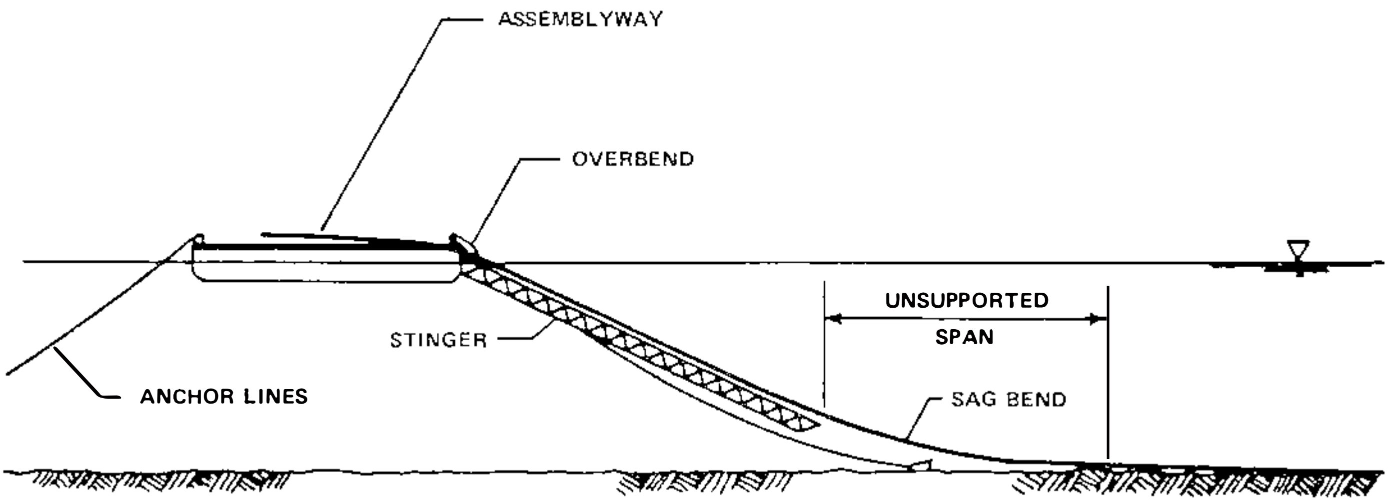


Figure 66. Conventional Lay Barge Construction Method with Straight Stinger and No Tension.

this avoids any imposition of undue stress on the pipe. Because of difficulties in handling these sometimes enormous stingers, which are used to convey the pipe to the ocean bottom, there is a limit to water depth in which this system may be applied. A second system is used which is less subject to the depth limitation (see Figure 67). The pipe, when held in tension between the barge and the ocean bottom, will form a catenary curve, which, in effect, converts it from a structural member to a cable member. As long as the tension is maintained as laying proceeds, the pipe is smoothly laid along the ocean bottom on the desired course.

When long lines are welded together joint by joint, the problem of maintaining tension is complicated by adverse weather and unanticipated shutdowns of the operation. To overcome this problem, a pipe reel system is sometimes used for small-diameter pipe (up to 12 inches) in which pipe joints are welded together onshore and several miles of line are wound onto a reel mounted on a barge or ship. The barge can then be moved into location for pipe laying, which can be accomplished in a few hours.

The most stable working platform of all is the land, and it is put to use as a pipe fabrication base when suitable. Frequently, a

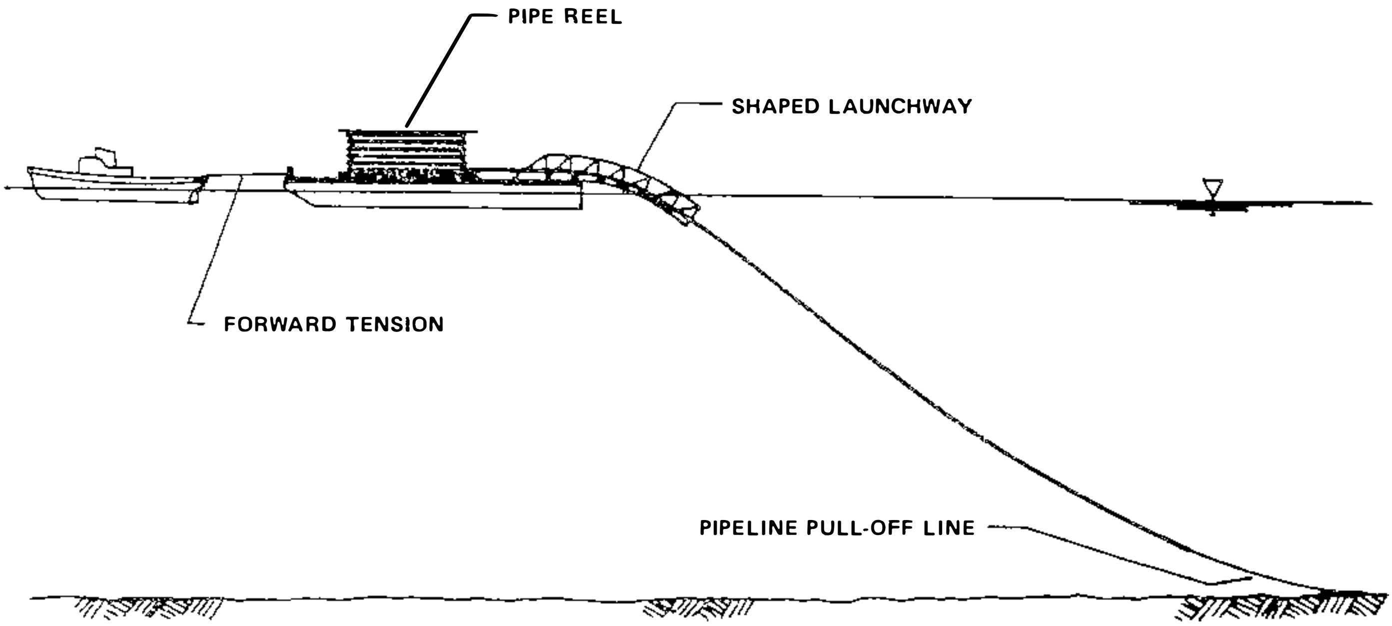


Figure 67. Reel Barge Construction Method Using Tension to Keep Pipe Stress Acceptable.

seagoing platform is required and a vessel is employed for the purpose. Conventional flat-bottomed barges are in common use as pipe-laying vessels. Ships are sometimes converted to pipe-laying vessels, usually as a matter of expediency in providing an inexpensive hull. The shipform vessel has a definite mobilization cost advantage because it tows well. In recent years, a semisubmersible type of pipe-laying vessel has been developed and is in common use for rough weather environments. Barges, ships, or semisubmersibles are selected depending upon anticipated sea state.

The launchway serves to transfer the fabricated pipe string from the assemblyway into the sea. It is an integral part of the working platform, although it may be designed to assume different angles or configurations. It may be a straight extension of a high-angled assemblyway, or it may be a curving transfer system carrying the pipe from a shallow angle on the assemblyway to a steep angle at the launching point.

One of the major problems encountered in laying underwater pipelines concerns the means of supporting the pipe span from the point at which the pipe can safely sag to bottom. A stinger is used except in very shallow water, to avoid excessive bending and possible buckling of a pipe. The stinger is unique to the lay barge. It is a detachable extension of the launchway, intended to support the pipeline during its descent from the barge to the sea floor. It may be a truss framework firmly attached to the barge or a buoyant pipe ladder hinged to the barge. It may be straight, or shaped for some purpose, usually to hold the overbend in the pipe within an allowable stress limit. Many stingers are designed to change their configuration by use of adding or subtracting air from the stinger's buoyancy chambers; this allows the stinger to change shape for various water depth or laying conditions.

By applying appropriate tension to the pipe, the stinger may be shortened, or even eliminated if the launching angle can be adjusted. During the welding operation on a lay barge, the pipe is gripped firmly so that tension may be applied through the barge positioning system. When the barge moves forward to launch a joint of pipe, however, the pipeline must be fed out in continuous tension, and the tensioner comes into play. The tensioner contains a fixed amount of holdback on the running pipe until the barge reaches its new position, where the positive stop is reset.

Pipe can be spooled into a radius of curvature in the yield range of the steel and then can be straightened through the yield point when unspooled, with no appreciable change in dimensional characteristics. Large-diameter reels are used to spool pipe for this purpose and offer a convenient way to carry great lengths of prefabricated pipelines in a small area (see Figure 67). Sizes larger than 12-inch diameter have not been adapted to this method; 6-inch diameter and smaller are the most common sizes of pipe using this lay method. Weight coating with concrete cannot be utilized with this method, but heavier wall pipe can normally provide the necessary weight for negative buoyancy.

A simple method to reduce the stress in a pipe string extending unsupported between the barge and the sea floor is to attach pontoons, which will relieve the submerged weight of the pipeline. Pontoons may also be used to reduce the submerged weight of a pipeline being pulled along the sea floor, and consequently, to reduce the pulling force.

C. Tank Cars and Trucks

1. Tank Cars

Railroad tank cars carry a smaller volume of oil and LPG than other modes of petroleum transportation, but are nevertheless important. They are used to transport finished products to bulk plants and consumers, and to move domestic crude oil from gathering areas to refineries, particularly in areas where pipelines are not available. Frequently, depending upon the location of marine facilities in relationship to blending operations, lubricating oils are transported in cars to the facilities and then loaded into tankers. This method of transporting lubricants ensures their integrity since clingage in pipelines would tend to contaminate subsequent batches of products passing through the lines. Heavy petroleum products, such as residual fuels and asphalts, are also frequently shipped by tank car.

As of June 15, 1979, there were approximately 202,800 tank cars, representing a 3.6 billion gallon capacity, in the U.S. rail car fleet. Of that total, 107,552 tank cars (2.2 billion gallon capacity) were considered to be suitable for carrying crude oil and petroleum products. These suitable cars reflect a 28 percent increase in capacity, but a 24 percent decrease in actual car count since 1967, indicating a trend of replacing older, smaller equipment with larger capacity cars.[10]

Tank car movement is restricted to service where tracks are available, thereby limiting its delivery capabilities. In this regard, tank cars are less flexible than trucks, but more flexible than either pipelines or water shipments, because tank cars can interchange throughout the U.S. railroad system.

Government agencies and industry organizations regulate and review tank car design and operations with respect to equipment design, compliance with local, state, and federal laws, and compatibility of tank cars with other cars in the train. For example, DOT regulation No. HM 144 -- Retrofit -- Hazardous Materials Regulations for Pressure Tank Cars required the retrofitting of approximately 22,000 pressure tank cars. This process included the insulation of the outer shell of tank cars to enable them to withstand specified temperature exposure tests, and the addition of head shields and special couplers to prevent mounting or head puncture by adjacent cars.

Tank car operations are also affected by the railroads that move the cars and by the regulations imposed upon them. For example, because of the poor condition of certain track, speed restrictions have been imposed on the railroads by the Federal Railroad Administration, thereby decreasing the efficiency of tank cars moving over them.

The total number of railroad systems is being reduced as a result of the mergers of individual lines and systems into single lines (e.g., Conrail). The operational and administrative functions of railrods are basically monitored by the American Association of Railroads, with certain constraints imposed by various government agencies.

The railroads, as common carriers, are required to supply all types of equipment for shipper use except tank cars. Railroads own relatively few tank cars (4,817 of the 202,800 cars in service in 1979), and those that they do own are used primarily in their own service.[11] Shippers either own their own cars or lease their tank cars from tank car manufacturers or leasing companies.

2. Tank Trucks

Tank trucks are extremely flexible for petroleum product deliveries, as they travel both regular and irregular routes and are not as restricted in their movements as are rail cars. This flexibility permits trucks to make many small quantity deliveries; for example, deliveries of home heating oil from bulk plants to consumers and gasoline from terminals and bulk plants to service stations. Trucks are also used in crude oil producing areas, to pick up crude oil at the wellhead and deliver it to gathering points for shipment through pipelines to refineries. Trucks are more economical for short hauls and deliveries of small quantities when compared to other modes of transportation.

It is estimated that, as of December 31, 1978, there were over 50,000 tank vehicles in the United States, each with a capacity of

over 3,500 gallons, and a total capacity of about 364 million gallons. Although these tank vehicles were not all designed primarily for petroleum service, they could nonetheless be used to haul petroleum in an emergency.[12]

The increased operating efficiency of the tank truck industry has resulted in a decrease in the number of vehicles required to be in service. An important factor in this greater efficiency is the implementation of 24-hour loading and unloading at terminals, which permits increased utilization of individual units.

Of equal significance is the impact of the Federal-Aid Highway Amendments of 1974, which permitted states to increase vehicle size and lessen weight restrictions. As a result of this legislation, gross loads have increased from the pre-1974 nominal limit of 73,280 pounds to 80,000 pounds in most states.

D. Waterborne Transportation

More petroleum is carried by water than is any other commodity. Petroleum commerce in the United States is categorized as either domestic or foreign traffic. Domestic traffic is composed mostly of barges and lake and coastal tankers; foreign traffic is that between the United States and foreign countries by means of ocean-going vessels. Some of the ports that service both forms of traffic are congested and a strain has been placed on facilities due to the increased demand for petroleum-based energy.

The most significant development in the early 1970's was the construction of Very Large Crude Carriers (VLCCs) and Ultra Large Crude Carriers (ULCCs). VLCCs have capacities less than 320,000 DWT (2.3 million barrels), while ULCCs have capacities up to 550,000 DWT (4 million barrels). Since 1971, the world's merchant fleet and tanker fleet have increased substantially, both in terms of the number of ships and their average and total deadweight capacity. Over the past several years, however, demand for tanker capacity has declined, and as a result many of these large tankers are now laid up or are being used for storage. Summary statistics for the merchant and tanker fleets are shown in Table 48.

Existing U.S. ports are limited by controlling depths, which restrict the deadweight tonnage of tankers operating in domestic ocean trade. Table 49 indicates that most U.S. ports are limited to vessels under 50,000 DWT, with very few ports able to accommodate tankers above 150,000 DWT. The extreme northern and southern ports of the Pacific Coast including Alaska are the only ones with enough depth to accommodate large vessels in the 150,000 to 250,000 DWT range.

Because of the severe operating restraints posed by controlling water depths at U.S. ports, the 1970's witnessed the growth and development of other marine logistic systems to permit the economies of large size crude oil carriers for meeting escalating

TABLE 48

World Merchant and Tanker Fleets -- 1971 and 1980*

	1971	1980
World Merchant Fleet		
Number of Ships	55,041	73,832
Total Gross Tonnage	247,202,634	419,910,651
World Tanker Fleet		
Number of Ships	6,292	7,112
Total Deadweight Tons	169,354,743	339,801,719
Average Deadweight Tons	26,900	47,800

*Source of data: "Statistical Tables," Lloyd's Register of Shipping, 1971 and 1980.

domestic import requirements. These developments in the U.S. crude oil delivery system included the following:

Transshipment Terminals. There are currently five major oil transshipment terminals in the Caribbean area having a total throughput capacity in excess of 3 MMB/D. Reflecting the trend of dramatically increasing tanker size during the last decade, these terminals were designed to accommodate vessels up to 500,000 DWT. After crude oil is delivered to the storage facilities at the terminal, shuttle vessels are loaded to the maximum draft permitted by the receiving U.S. refinery. The Caribbean terminals provide the economics of tanker size to the U.S. consumer. In contrast to the transshipment concept, major oil consuming nations in Europe and the Far East have enjoyed for many years the economic benefits of direct deliveries of large size crude carriers due to the early development of their deepwater ports.

Vessel Lightering. Vessel lightering is the ship-to-ship transfer of crude oil from a large tanker directly into smaller vessels whose draft will permit transit to shallower water coastal facilities. The lightering operation is an alternative to the transshipment terminal discussed above. In some cases, such as on the Delaware Bay, intermediate sized vessels are partially off-loaded by lightering before proceeding to the receiving port. In other locations, such as in the U.S. Gulf and in Panama, lightering operations are used to fully off-load VLCCs and ULCCs into vessels whose draft will permit passage to coast refinery ports or through the Panama Canal.

U.S. Deepwater Ports. The industry for many years has recognized the need for the construction of deepwater ports in the United States, and several projects have been proposed during the past ten years. The Louisiana Offshore Oil Port (LOOP), which is

TABLE 49

Controlling Depth and Maximum Permissible
Size Vessels for U.S. Ports

Port or Harbor Area	Controlling Depth (Feet)	Estimated Maximum Permissible Vessel Size When Fully Loaded (DWT)
East Coast		
Delaware River Ports	40	53,000
Hampton Roads, VA	45	30,000
New York, NY	35	40,000
Portland, ME	45	30,000
Baltimore, MD	42	53,000
Boston, MA	40	40,000
Gulf Coast		
New Orleans, LA	40	50,000
Tampa, FL	34	35,000
Baton Rouge, LA	40	50,000
Mobile, AL	40	45,000
Corpus Christi, TX	45	50,000
Houston, TX	40	50,000
Brownsville, TX	36	30,000
Pascagoula, MI	38	35,000
Pacific Coast		
Long Beach, CA	52	150,000
Los Angeles, CA	51	150,000
San Francisco Bay Ports	35	40,000
Puget Sound, WA	73	250,000

SOURCE: U.S. Department of Commerce, Maritime Administration Tanker Construction Program, US-124, Shipping Data, Waterborne, Final EIS, AN73-0725-F, 1973.

partially operational and scheduled for completion in 1982, is the first project to actually obtain the necessary permits and operating licenses to proceed. LOOP has a design capacity of receiving 1.4 MMB/D of crude oil, and will handle the equivalent unloading of some 330 VLCCs per year during its first year of full operation. The discharge facilities consist of three single point mooring buoys, which are located in 110 feet of water at a point 19 miles offshore. Vessels of up to 700,000 DWT can be safely accommodated. LOOP and its associated pipeline system (LOCAP) are projected to displace approximately 85 percent of the crude oil movements presently being transported on the lower Mississippi River in small tankers.

1. Inland Waterways

In the past 40 years, tonnage shipped on the nation's inland waterways (primarily rivers and harbors) has more than tripled and the average length of haul has increased from 50 to 375 miles. Rapid technological development has led to vast improvements in productivity. Development of the medium speed diesel engine, the Kort nozzle, the tunnel hull, the swing indicator, radar, and telecommunications has enabled operators to increase maximum tow size from 5,000 to 30,000 tons. Marine operating systems are, however, presently reaching the physical limitations of the inland waterways system. Past increases in productivity have given way to a more modest pace of improvement in hardware and operations in recent years. Evolutionary refinements have replaced revolutionary changes as technology advances.

The inland waterways industry consists of some 1,800 towing companies operating on more than 25,000 miles of inland waterways which serve 87 percent of the major cities in the nation. The inland fleet amounts to over 4,300 towboats and tugs with a combined horsepower equivalent of 6.1 million. Tank barges number 3,971 with a total capacity of 71.3 million barrels. Not all of the 1,800 towing companies carry petroleum, and some carry many different commodities in addition to petroleum.[13]

A growing percentage of petroleum products is moved by barge, but of increasing importance is the new integrated tug barge concept (Figure 68). These units will be used to supplement ocean tankers in coastal service.

The 25,000 miles of inland waterways that constitute the inland waterways system of the United States include navigable rivers, intracoastal waterways, canals, channels, and other waterways (Figure 69). In order to be considered navigable, a waterway must permit the movement of a sufficient quantity of products to be commercially economic. Water depth, the width of the waterway, and the navigability of its bends, locks, and channels are important. Nearly 25 percent of the total inland waterways system is less than six feet deep and almost 80 percent is less than 14 feet deep.

There are many constraints that affect inland barge transportation. Weather is the biggest factor and affects the navigational seasons through icing or flooding. Low water resulting from lack of rainfall also poses a real threat to navigation. Movement of commodities by barge is also limited by terminals and material handling equipment, as well as navigation aids. Improving these areas would complement the advanced technology of tug operations and contribute to improved productivity and safety on the inland waterways.

2. Maritime Carriers

Coastal tankers and tug barges are especially important in the transportation of petroleum along the U.S. coast (Figures 70 and 71). Tankers of between 17,000 and 50,000 DWT are most prominent

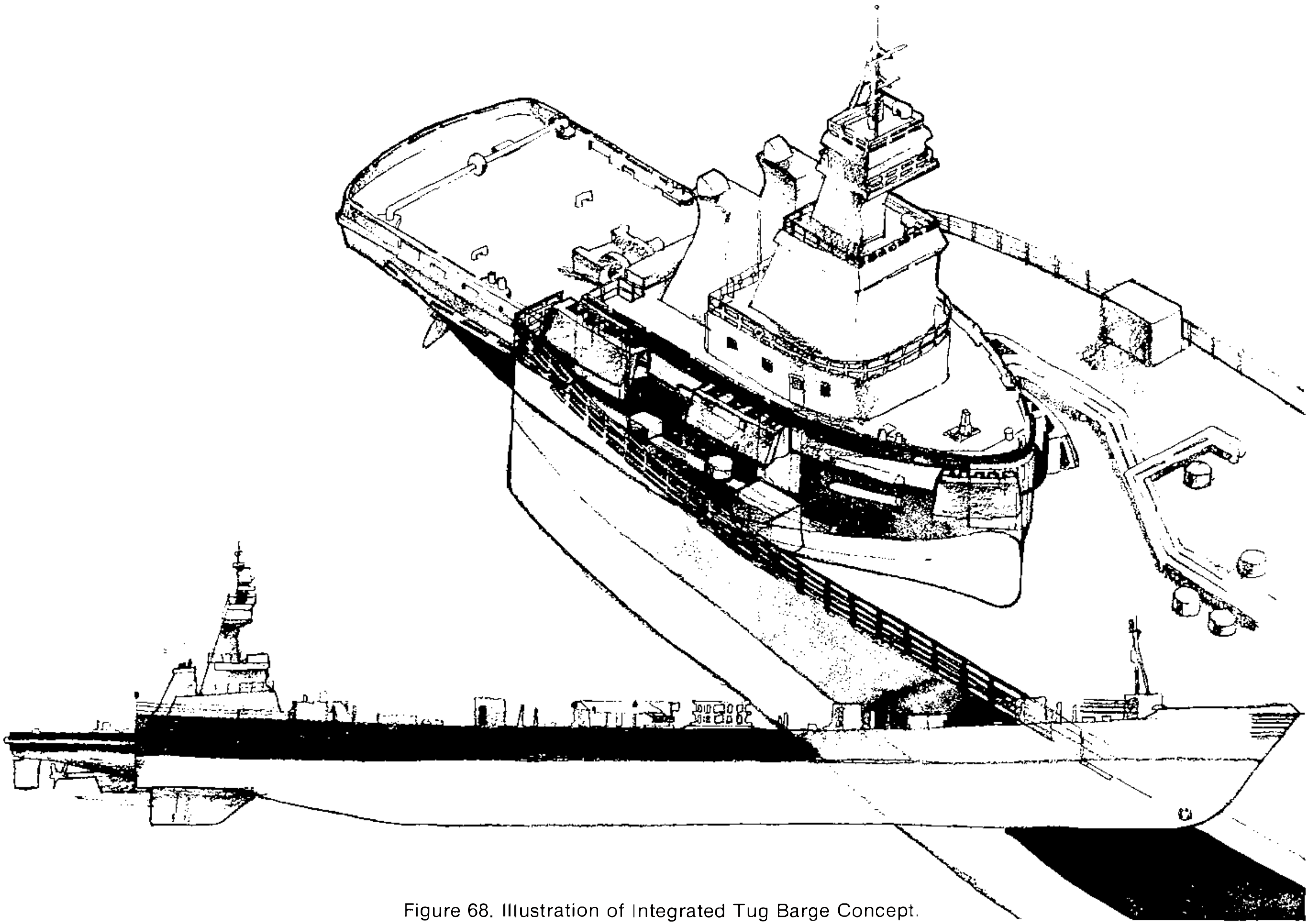


Figure 68. Illustration of Integrated Tug Barge Concept.

SOURCE: Gulf Oil Corporation.

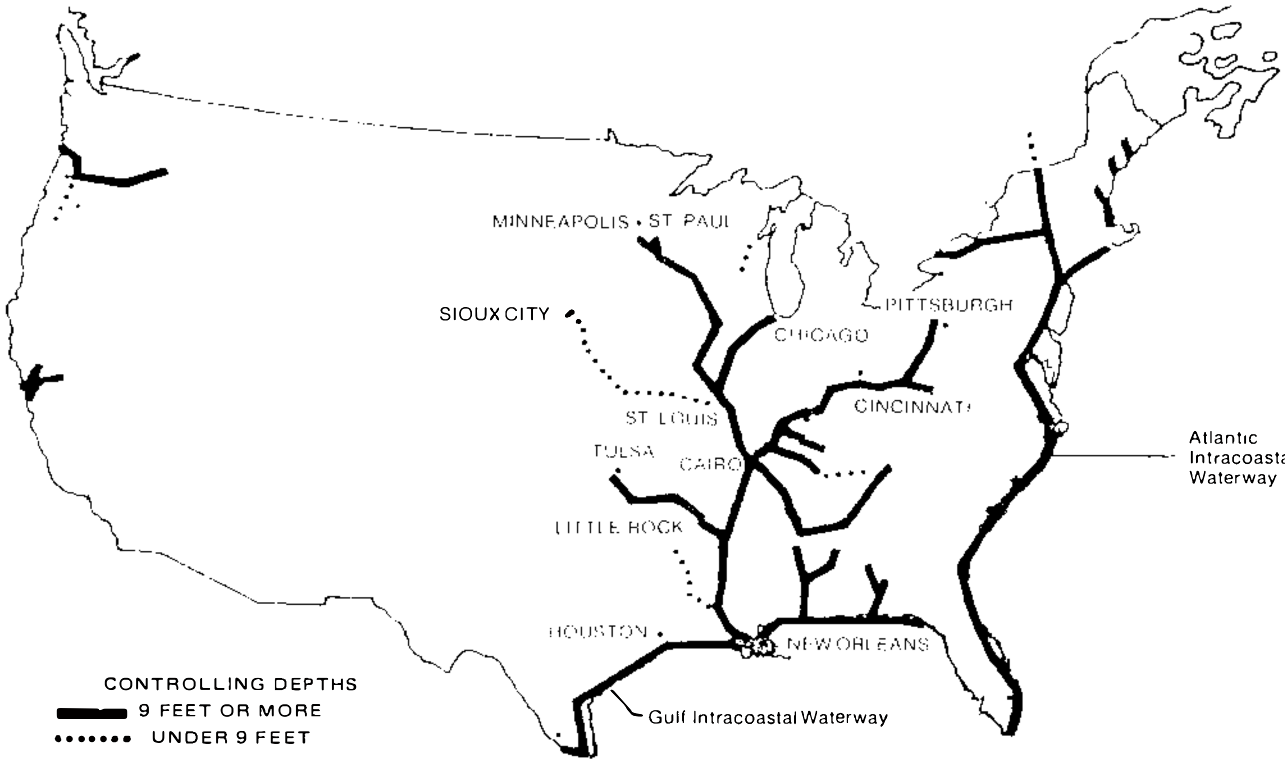


Figure 69. Commercially Navigable Waterways of the United States.

SOURCE: National Petroleum Council, *Petroleum Storage Transportation Capacities,* 1979; adapted from *Final Environmental Impact Statement, Title XI;* U.S. Department of Commerce, Maritime Administration, February 1979.

Figure 70. Location of Refineries and Tanker Terminals Accessible from the Coast.

SOURCE: National Petroleum Council, *Petroleum Storage and Transportation Capacities,* 1979; adapted from U.S. Department of Commerce, Maritime Administration *Final Environmental Impact Statement, Title XI,* February 1979.

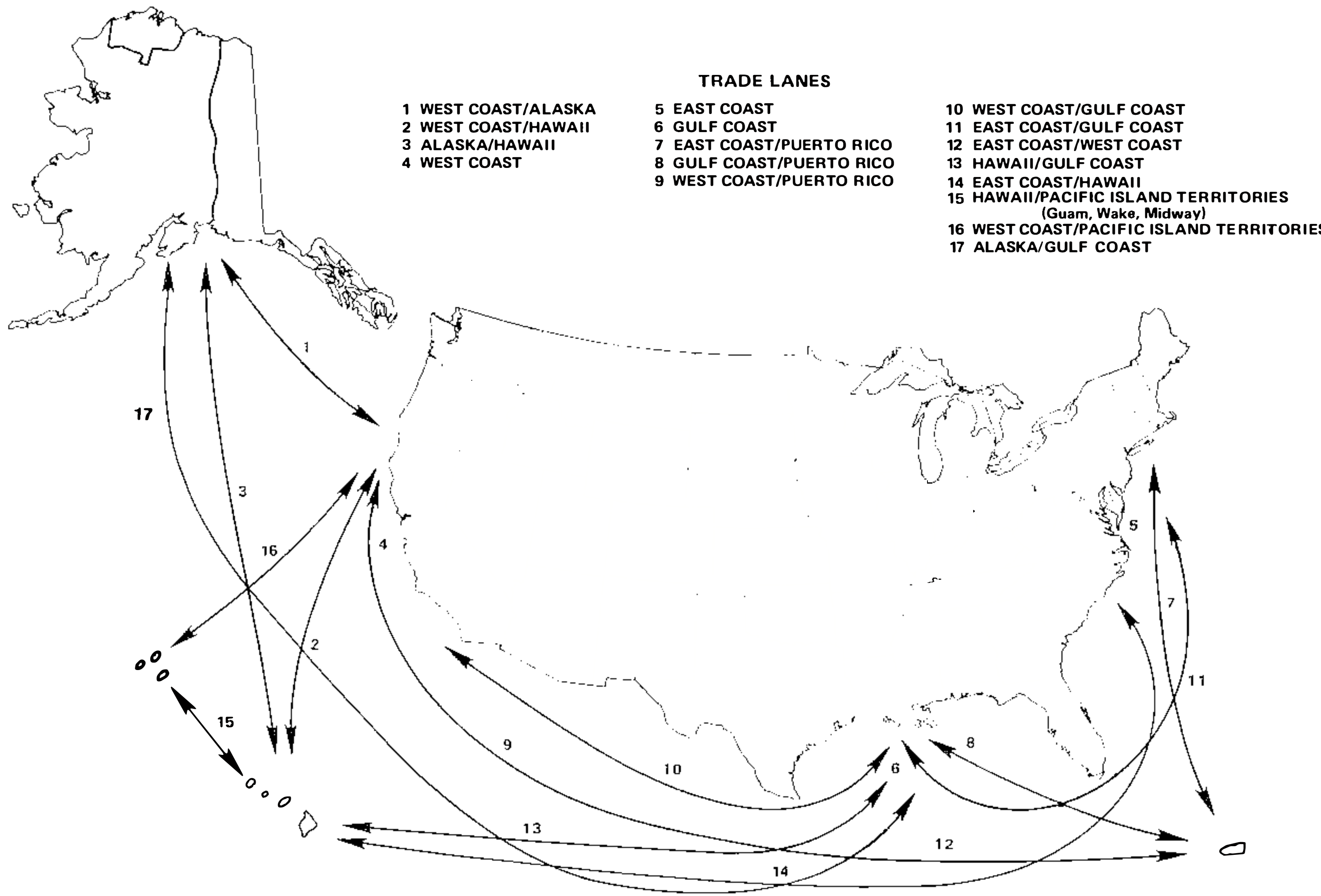


Figure 71. Domestic Waterborne Trade Lanes.

SOURCE: National Petroleum Council, *Petroleum Storage and Transportation Capacities*, 1979; adapted from U.S. Department of Commerce, Maritime Administration, *Final Environmental Impact Statement, Title XI*, February 1979.

in the carriage of petroleum products, of which gasoline is the largest quantity. Crude oil movements from Alaska to the west coast and to the Gulf and east coasts via the Panama Canal have reached substantial levels in the past several years utilizing various sizes of tankers, including VLCCs. Most of the coastal tankers average 16.5 knots. Tankers and barges of a smaller size (up to 35,000 DWT) can generally be loaded or unloaded in 24 hours under ideal conditions, while the large tankers require between 24 and 36 hours.

In recent years, ocean barging has become an important factor in petroleum transportation, and greater use is likely in the future. These large vessels (of up to 45,000 DWT) are either pushed or pulled by oceangoing tugs. The smaller oceangoing barges are commonly used to supply fuels from refineries to nearby urban centers or transshipment terminal points. The larger ones operate much as self-propelled coastal tankers do.

Despite its size and cargo, the oceangoing tanker is basically a large, strong metal tank that is subdivided into smaller tank compartments and is narrow in the bow and stern. The power unit and control system are located in the stern. Of major concern in the design of the oceangoing tanker are: the service requirements that determine whether a ship will be a large one built to transport crude oil between a limited number of ports, or a smaller, specialized vessel built to move refined products shorter distances; limiting dimensions, including draft, beam, and length, which combine to dictate the amount of deadweight that can be lifted by the hull; and speed, which is largely dependent upon the power available and the shape of the hull. The annual cargo-carrying capacity of a tanker is increased as a function of its speed since trip time is reduced.

Scheduled maintenance is a major part of the operating costs of a tanker. Drydocking for extensive maintenance activity typically occurs on a biannual basis.

II. The Gas Transmission System

The vast majority of domestic gas is produced in the southwestern states and off the coasts of Louisiana and Texas in the Gulf of Mexico. While these states consume significant quantities of natural gas, other major areas of consumption include the north central, northeastern, midwestern, and middle Atlantic states, and California. The natural gas transportation industry supplies a link between the gas producing and gas consuming regions of the country. Through an intricate network of pipelines, the industry provides gas to consumers in nearly every area of the contiguous United States.

Gas pipeline companies usually own a major portion of the gas moving through their respective systems; they also transport significant volumes of gas owned either by their customers or by other pipeline companies.

Natural gas is normally purchased by gas pipeline companies from production companies in the gas fields. These gas pipeline companies transport the gas to the market area where it is sold to distribution companies, which make deliveries to the end use consumer. The components of a typical gas system from wellhead to consumer are shown in Figure 72.

As existing gas reserves are constantly being depleted and new gas reserves discovered and developed, the gathering segment of a pipeline must expand to connect new supply areas to the pipeline. In general, new gas discovery areas have become increasingly remote and in recent years have included the Rocky Mountain region as well as offshore locations in the Gulf of Mexico.

Gathering pipelines funnel into the main line transmission portion of the system. It is the main line segment, often consisting of parallel lines with compressor stations every 40 to 130 miles, that spans the distance between the gas field and the market area. In contrast to the web of gathering lines, the main line follows a relatively straight cross-country course.

Once at the market area, gas is sold and delivered to various distribution companies, local utilities, and in some instances, directly to industrial customers. Often the delivery points are located directly on the main line. It is also common for deliveries to be made through a lateral line that branches out from the main line to link up with the buyer's distribution system.

A. Gas Pipelines

Gas is frequently sold and exchanged from one pipeline company to another through interconnections in their pipeline systems. As a result of the many interconnections that have been established, a complex pipeline grid extends across the nation (Figure 73). This grid gives the industry considerable flexibility to respond to changes in supply locations or demand patterns. Separate pipeline companies traditionally interact with one another through these interconnections to maintain gas flow during short-term system outages (e.g., maintenance). This voluntary interaction between individual companies provides the United States with the flexibility of a national pipeline grid while preserving the service and responsibility of independent pipeline companies.

Gas pipeline companies must also be prepared to meet extremes, or "peaks," in demand. Gas flow on a peak day may be quite different from that on a normal operating day. Peak day demands are met not only from pipeline supply, but also from underground storage, LNG and synthetic natural gas facilities, gas diverted from customers with noncritical needs, and other supplemental supplies. Pipeline systems must be designed to handle these other inputs, with the result that there is spare capacity in portions of the pipeline system. It is this design that gives flexibility to the total pipeline network in the United States.

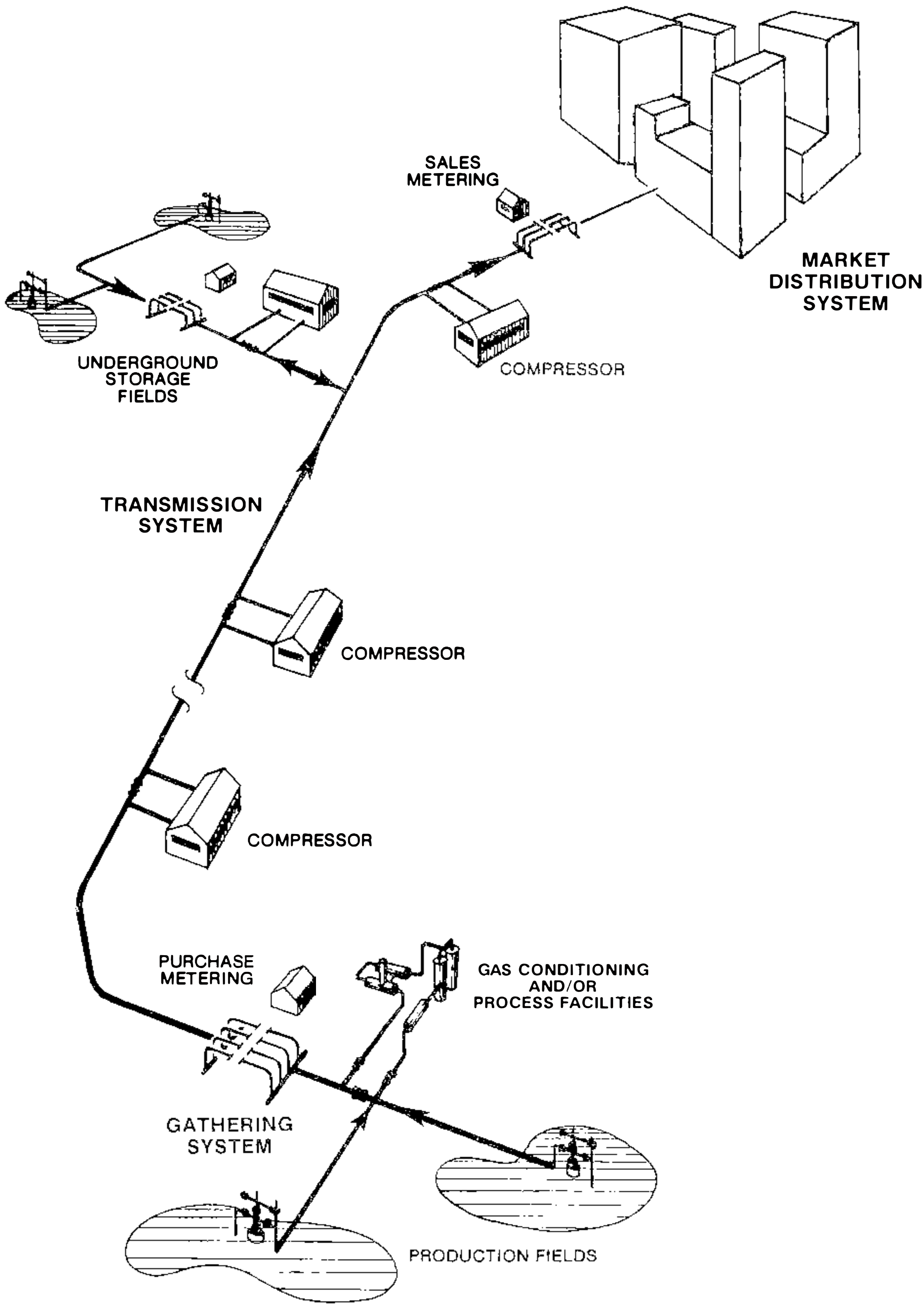


Figure 72. Typical Natural Gas Pipeline System.

SOURCE: National Petroleum Council, *Petroleum Storage and Transportation Capacities*, 1979.

Pipeline construction and operation are regulated by several government agencies. Permits must be acquired prior to the construction of facilities, and pertinent operational parameters (e.g., noise and emission of air and water pollutants) must be monitored and maintained at acceptable levels. These requirements have resulted in an increase in the time required to plan and install new facilities.

The Natural Gas Pipeline Safety Act of 1968 (modified by the Pipeline Safety Act of 1979) controls natural gas pipelines. The DOT industry safety guidelines regulate every aspect of pipeline construction and operation.

MARKETING[14]

Petroleum marketing in the United States is a very large and complex operation. It involves the delivery of about 17 MMB/D of a wide range of petroleum and gas products from refineries and storage points to consumers across the land. These products include motor and aviation gasoline, jet fuels, kerosine, diesel fuel, fuel oils, LPG, petroleum coke, lubricants, greases, waxes, and asphalt.

Petroleum marketing also has some rather unique characteristics. Oil products are almost constantly on the move. Initially, the crude oil moves from producing fields scattered all over the globe to refineries. From refineries, oil products move next to distribution and storage points, and then quickly to consumers. This flow cannot be interrupted for any great length of time if consumers are to be served effectively.

Each of the many hundreds of petroleum products has its own flow pattern from refinery to consumer. The methods for marketing the wide variety of petroleum products are almost as varied as the products themselves. Some products, such as motor oils and grease, are packaged in drums and smaller containers, which are then shipped in trucks and boxcars to consumers or intermediate storage facilities. Other products, such as industrial oils, are sometimes shipped in bulk or in very large containers as well as in drums. This section briefly describes the distribution of gasoline and fuel oils, the industry's principal products, to provide an understanding of the basic petroleum marketing channels.

I. Distribution Channels

Moving petroleum products from the refinery to resellers and consumers most frequently involves the use of intermediate storage facilities, known as terminals and bulk plants. In this country, approximately 25,000 terminals and bulk plants perform this essential function.

The movement of products from the terminal or bulk plant is handled by refiner-marketers or distributors. A refiner-marketer generally sells his products under his brand name to distributors, fuel oil dealers, service station dealers, and consumers. He may

MAJOR NATURAL PIPELINES

also sell unbranded products to distributors, fuel oil dealers, and service station dealers, who then market the products under their own brand names. A growing amount of branded and unbranded product is sold to convenience store owners and other retailers.

A. Petroleum Terminals

Petroleum terminals are large distribution centers where petroleum products are received by pipeline, marine tanker, barge, or rail car. Storage facilities at terminals vary considerably, depending upon how they receive their products, the market area to be served, and the number of days that storage is needed for the area. Terminals store and redistribute products to petroleum bulk plants, wholesale distributors, fuel oil dealers, service stations, other retailers, and large consumer accounts.

Shipments out of terminals are mostly by trucks or railroad tank cars. Very large consumers, such as airports, may be served directly by pipeline from a terminal or refinery.

B. Bulk Plants

Bulk plants are smaller than marine or pipeline terminals and they receive shipments of petroleum products by truck, either from refineries or terminals. These products are then redistributed by tank trucks to large consumers, homeowners, farms, and service stations. Bulk plant operators who buy petroleum products outright from a refiner or terminal are performing a wholesale function and are referred to as distributors, or "jobbers." Another type of bulk plant operator who performs a wholesale function for oil supplying companies is known as a "salary agent" or "commission agent," depending upon whether he receives a salary or commission from the oil supplier.

II. Marketing of Petroleum Products

A. Fuel Oil Distribution

The demand for fuel oils, particularly home heating oil, is seasonal in colder areas of the country. As a result, ready availability during high demand periods requires the fuel oil suppliers to build up storage quantities in summer to ensure adequate supplies in winter when demand is greatest. It is also at such times that fuel oils are required to satisfy the need of industries whose supply of other fuels has been interrupted. In addition to home heating, large quantities of fuel oil are also used by industries such as primary metals, chemicals, utilities, and textiles.

B. Gasoline Retail Distribution

There were about 158,000 primary service stations in the United States in 1980. In addition, there are over 100,000 secondary gasoline outlets. The primary service stations are defined as those locations where at least 50 percent of the business is accounted for through the sale of petroleum products. The secondary

outlets are such facilities as parking garages; automobile dealerships; convenience, department, and discount stores; and repair garages where gasoline is sold but does not account for as much as one-half of the operator's sales. In all, there are about 260,000 outlets from which gasoline can be supplied to the vehicles in this country.

Over 90 percent of all gasoline service stations are operated by independent, self-employed local business people. The remaining service stations, less than 10 percent of the total, are "company operated" by refiner-marketers, branded distributors, or private distributors. Dealers may purchase their product from either refiners or jobbers. Stations selling the trademarked product of the larger oil companies are referred to as "branded outlets." Full service stations account for about 44 percent of all stations, and split island stations (where consumers can buy gasoline either on a self-service or attended basis) account for about 22 percent.[15]

As a result of higher gasoline prices and greater fuel efficiency of automobiles, the total consumption of gasoline in the United States is expected to slowly decrease in the period through 1990. This decreasing demand has caused changes in the marketplace, resulting in the closing of many marginally profitable operations and a shift toward less labor intensive self-service operations and higher volume service stations.

C. Marketing of Other Petroleum Products

In all, more than 3,000 different products are made from petroleum and are marketed in a number of different ways. Some examples follow.

Diesel fuel is marketed at truck stops and a growing number of service stations all across the United States. The railroads of the United States run on diesel fuel also, and the major airlines consume huge quantities of jet fuel. Aviation gasoline is sold at general aviation airports for use in planes powered by reciprocating engines. And, of course, both airplane and railroad engines require their own specialized lubricants.

For the farm, petroleum-based liquid fertilizers are a necessity today and LPG is used for a variety of heating and crop-drying purposes. Waxes and asphalts and industrial oils, such as those for metal working, hydraulic systems, textile machinery, transformers, and general purpose use, all represent important uses of petroleum.

ENVIRONMENTAL CONSIDERATIONS

INTRODUCTION

There are many diverse environmental considerations in the storage, transportation, and marketing functions of the petroleum industry. The storage, transportation, and marketing of petroleum raw materials and products are conducted in a predominately closed system -- tankers, barges, storage tanks, pipelines, tank cars, tank trucks, and service station underground tanks. This closed system acts to protect product quality, ensure the safe handling of materials, and minimize releases to the environment. Some releases do occur at points of transfer, during storage, during equipment maintenance and cleaning, through accidental spills, and through disposal of petroleum products (such as used lubricating oils). This section discusses these releases and their control under existing environmental laws and regulations. Emissions and releases resulting from the use of petroleum products are discussed in Chapter Five.

AIR

Hydrocarbons [volatile organic compounds (VOC)], and nitrogen oxides (NO_x) are the primary air pollutants of concern of this segment of the petroleum industry. Hydrocarbons emissions can occur at many points throughout the distribution system, but primarily during storage and transfer. NO_x emissions arise from fuel-burning engines used to drive pumps and compressors that move materials through the system. Both pollutants are subject to environmental regulation.

I. Federal and State Standards and Regulations

The Clean Air Act and its associated federal regulations outline the requirements that the states must follow in managing air quality. The states, in turn, enact legislation and promulgate regulations that carry out the federal mandates. While the states may be more stringent than the federal mandates, they may not be less stringent or the federal requirements will apply. Thus, state laws and regulations govern the operation of air pollution control activities at the local level, and these laws and regulations will meet federal requirements.

States, in turn, may enact legislation that vests much of the authority for carrying out the emission control programs with local air pollution control agencies organized on a county, district, municipality, or regional basis. These local offices ensure that the federal and state regulations for control of existing and new and modified stationary sources are enforced in their jurisdictions. They also carry out inspections and other types of enforcement activities and in general operate as the "first line" in air pollution control activities.

The storage, transportation, and marketing sector of the industry has been primarily concerned with those regulations that involve only hydrocarbon and NO_x emissions in both nonattainment and Prevention of Significant Deterioration (PSD) situations. In these situations the regulations applicable to this sector are the same as those for the rest of the industry, although the emission control equipment in most cases may be different.

In nonattainment areas, existing sources must meet Reasonably Available Control Technology (RACT), while new and modified sources usually must meet New Source Performance Standards (NSPS) and Lowest Achievable Emission Rate (LAER) requirements. These requirements specify the emission controls that are mandated to bring nonattainment areas into attainment. In attainment areas, NSPS and Best Available Control Technology (BACT) requirements apply to new and modified sources. While these distinctions are generally applicable, each application for a permit to construct or modify a storage, transportation, and marketing source is considered individually. Because of such considerations as air quality, location, concentration of other emission sources, and population patterns, the specific level of control to be applied is determined by negotiation. Thus, control technology meeting the requirements for a given level of control may be similar, but not necessarily identical, to the same control technology applied elsewhere.

The Clean Air Act Amendments of 1977 require each state in which there is a nonattainment area to adopt and submit a revised State Implementation Plan (SIP). In revising their SIPs, states must develop and adopt regulations applicable to existing stationary sources of VOC emissions and these regulations must reflect the use of RACT.

To provide state and local air pollution control agencies with an information base for proceeding with development of appropriate regulations, the Environmental Protection Agency (EPA) has published a series of Control Technique Guideline (CTG) documents. The CTGs present a review of existing information concerning the technological and economic feasibility of various control techniques to reduce VOC emissions, and suggest emission limits that EPA considers the "presumptive norm" broadly representative of RACT for the entire stationary source category. In addition, the documents include a "model regulation" based on the control techniques and emission limits.

CTG documents are of necessity general in nature and do not fully account for variations within an industrial source category. Thus, there may exist a number of reasons for regulations developed by state and local control agencies to deviate from the "presumptive norm" included in a CTG document. The CTG document, however, is a part of the rulemaking record that EPA considers in reviewing revised SIPs, and the information contained in the document is usually highly relevant to EPA's decision to approve or disapprove the SIP. In the past, EPA withheld approval of the SIP until CTG language had been included.

Industry has been critical of the CTGs primarily because the documents are not subject to formal rulemaking procedures during their development or prior to publication. Although EPA may incorporate industry input from review of the drafts, the carefully worded technical provisions are in some instances subverted when the model regulation in the document editorially imposes more restrictive requirements without justification and without assessment of their cost effectiveness. A more formal review process could reduce the likelihood of this problem.

The need for an improved procedure is emphasized when the CTGs are interpreted by the states or EPA regions to be standards or regulations rather than guidance documents. This has frequently led to more stringent regulations, with resulting higher costs, than were necessary to satisfy air quality requirements.

II. Emission Trends

Total emissions of pollutants into the air from storage, transportation, and marketing facilities and operations consist principally of VOCs and a small amount of emissions arising from associated pumping and mobile source equipment. Most of the emissions arising from these sources are criteria pollutants, i.e., pollutants for which National Ambient Air Quality Standards (NAAQS) exist. However, one of the VOCs, benzene, has been identified as a hazardous air pollutant under Section 112 of the Clean Air Act [National Emission Standards for Hazardous Air Pollutants (NESHAPS)], and additional steps may be required in the future to reduce public exposure. The following sections outline the trends of emissions from these pollutants and the considerations involved in their handling in this sector.

A. Criteria Pollutants

The emissions of VOCs largely occur from crude oil or light liquid products such as motor gasoline, aviation gasoline, or military jet fuel. Emissions occur during storage and when the liquid is transferred, loaded, or unloaded. VOCs are also emitted to the atmosphere through the leaks that occur in the seals on pumps, valves, and flanges. Leaks are a very small source of fugitive emissions when the equipment is adequately maintained.

Particulate matter, NO_x, sulfur oxides (SO_x), and carbon monoxide (CO) are emitted as components of the exhaust gases of engines and turbines used to pump and transport crude oil, natural gas, and products. In addition, petroleum industry storage, transportation, and marketing activities create some dust, which adds to atmospheric particulate matter. Dust is raised from roads and road beds traversed by tank trucks and railroad tank cars. Also, tank farms often contain unpaved roads from which the wind and vehicle movement can loft dust. These emissions from exhausts, vehicle movements, and the roads of storage areas are small compared to other petroleum industry contributions and are insignificant compared to national totals.

Total emissions from storage, transportation, and marketing generally are widely dispersed geographically and are difficult to estimate with a high degree of accuracy. Therefore the aggregated emission estimates published by EPA and used in this discussion are not highly accurate in an absolute sense; however, they are useful for describing general trends and the relative levels of emissions from various sources.[16]

Probably the most accurately known of the various pollutant emissions are the VOCs. Table 50 shows national estimates for 1979 of about 24.6 million metric tons per year from all sources in the nation. Within the petroleum industry, about 0.6 million metric tons result from crude oil production, storage, and transfer, and about 1.8 million metric tons result from petroleum product storage and transfer.

TABLE 50

1979 Hydrocarbon (VOC) Emissions*
(Millions of Metric Tons Per Year)

	VOC Emissions
National Total	24.6
Crude Oil Production, Storage, and Transfer	0.6
Petroleum Product Storage and Transfer	1.8

*Source of data: Environmental Protection Agency, National Air Pollutant Emission Estimates, 1970-1979, March 1981.

Table 51 shows little or no trend over the years 1970-1979 in the national total VOC emissions or in the petroleum industry contributions. Over this 10-year period, there has been a substantial increase in petroleum industry throughput as indicated by a 35 percent increase in crude oil refined and a 22 percent increase in gasoline demand. The lack of a corresponding increase in emissions reflects rather extensive implementation of VOC emission controls in the industry.

Emissions of particulate matter, NO_x, SO_x, and CO from storage, transportation, and marketing operations are believed to be from one to several orders of magnitude lower than those of VOCs. However, except for NO_x, no nationwide estimates are available. The petroleum industry contributes approximately 6 percent to the national NO_x emissions and petroleum storage, transportation, and marketing contributes about one-half of one percent (Table 52).

TABLE 51

Estimated Hydrocarbon Emission Trends -- 1970-1979*
(Millions of Metric Tons Per Year)

Year	National Total	Crude Oil Production, Storage, and Transfer	Petroleum Product Storage and Transfer
1970	27.7	0.59	1.7
1971	27.0	0.59	1.7
1972	27.4	0.60	1.8
1973	26.8	0.60	1.9
1974	25.5	0.58	1.8
1975	23.4	0.57	1.8
1976	24.4	0.58	1.9
1977	24.4	0.60	1.9
1978	25.4	0.61	1.9
1979	24.6	0.61	1.8

*Source of data: Environmental Protection Agency, National Air Pollutant Emission Estimates, 1970-1979, March 1981.

The impact of storage, transportation, and marketing emissions on air quality is small and widely dispersed with the greatest effects downwind of petroleum transportation terminals and densely populated (high-consumption) areas. The largest impact theoretically results from VOC emissions, which are precursors to photochemically generated ozone.

B. Hazardous Pollutants

VOCs emitted from petroleum storage, transportation, and marketing are composed of thousands of organic chemical compounds. Most of these compounds occur in minute quantities in the emissions and are innocuous from the health standpoint. However, a few compounds may be hazardous at sufficiently high concentrations.

Among the many organic compounds occurring in small amounts, benzene is one of the more prevalent and it has been identified as

TABLE 52

1977 Nitrogen Oxide Emissions*
(Millions of U.S. Tons of NO_x [as NO_2] Per Year)

National Total	22
Petroleum Industry Total	1.3
Storage, Transportation, and Marketing Total	0.080
Marketing†	0
Transportation	
Crude Oil	0.068
Products	0.012

*Source of data: American Petroleum Institute, NO_x Emissions from Petroleum Industry Operations, October 1979.
†Includes storage.

a NESHAPS pollutant. The identification was made because benzene at very high concentrations in industrial uses has been associated with leukemia.

Benzene emitted from gasoline handling is estimated to be on the order of 0.8 percent of the total hydrocarbon emitted.[17] If it is assumed that all of the storage, transportation, and marketing VOC emissions in Table 50 are from gasoline, total benzene emissions from storage, transportation, and marketing would be on the order of 16,000 U.S. tons per year. Measured benzene concentrations in the ambient air at gasoline service stations have been found to range up to 50 parts per billion with an average of 6 parts per billion.[18]

Emissions of benzene and all the compounds present in storage, transportation, and marketing VOC emissions are reduced by emission controls. Consequently, benzene emissions have been reduced by the past application of these controls and are expected to continue to trend downwards in the future. At the present public exposure levels there is no significant health risk from benzene and no future public hazard is expected.

III. Storage Emissions

As stated in the Industry Operations section of this chapter, tremendous volumes of raw materials and refined products must be stored at various points in the petroleum distribution system. Five basic, above-ground, vertical wall tank designs are used for storage of large volumes of petroleum liquid: fixed roof, external

floating roof, internal floating roof, variable vapor space, and pressure (low and high). Small volumes of products are usually stored in cylindrical tanks, positioned horizontally above ground or, as at service stations, underground. The environmental considerations for these latter tanks will be addressed in the Marketing Emissions section of this chapter.

The type of storage vessel utilized depends primarily upon the volatility and volume of the material to be stored, the location and function of the associated facility, and the applicable environmental regulations. A volatile liquid such as gasoline would usually be stored at a terminal in large, external floating roof tanks; in a geographic area having inclement weather, however, internal floating roof tanks would be more typical. Lower volume storage of gasoline at a bulk plant normally would be in small, fixed roof tankage.

Petroleum products less volatile than gasoline are stored in a number of ways, depending upon local conditions and throughput quantities. For example, heating oil (No. 2 fuel) and residual fuel (No. 6 fuel), being essentially nonvolatile, are stored in fixed roof tanks. More volatile products, such as butane and propane, have high vapor pressures at normal ambient temperatures and therefore must be stored in pressurized tankage. Crude oil has an extremely variable vapor pressure depending upon the concentration of light hydrocarbons, and consequently, its storage includes both fixed roof and floating roof tanks. Because of environmental regulations, a low volatility crude oil might have to be stored in internal floating roof tanks in one area but could utilize fixed roof tanks in another area.

A. Tank Descriptions[19]

1 External Floating Roof Tanks

Typical external floating roof tanks are shown in Figures 74, 75, and 76. This type of tank consists of a cylindrical steel shell equipped with a deck or roof that floats on the surface of the stored liquid, rising and falling with the liquid level. The liquid surface is completely covered by the floating roof, except in the small annular space between the roof and the tank wall. A seal attached to the roof contacts the tank wall and covers the annular space. The seal slides against the tank wall as the roof is raised or lowered by addition or withdrawal of the stored liquid.

External floating roofs are currently of three general types: pan, pontoon, and double-deck. While numerous pan-type floating roofs are currently in use and are giving satisfactory service, the present trend is toward the other two types. Manufacturers supply various versions of these basic types of roofs, which are tailored to emphasize some particular feature, such as full liquid contact, load carrying capacity, roof stability, or pontoon arrangement.[20]

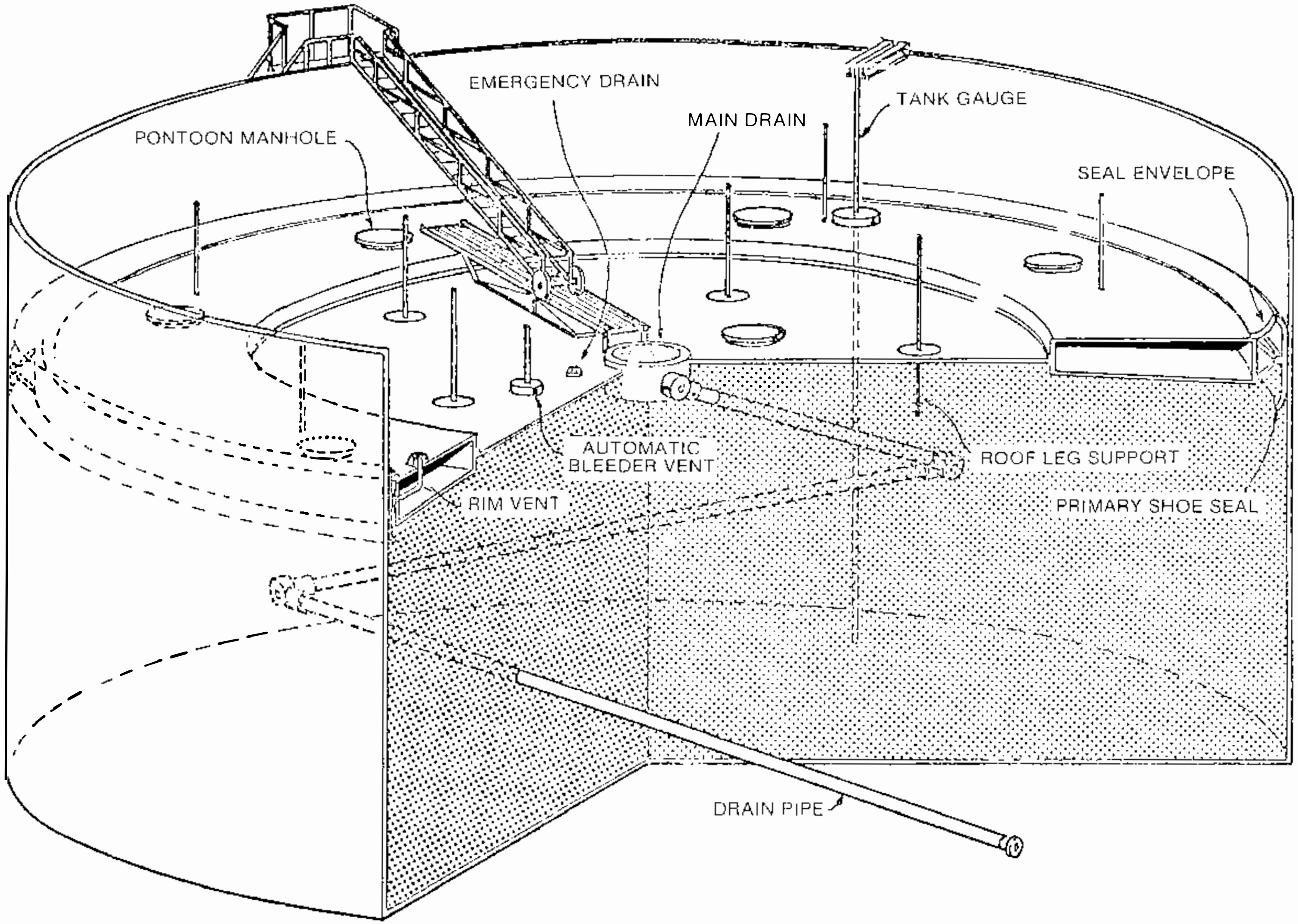


Figure 74. Pontoon-Type External Floating Roof Tank.

SOURCE: Environmental Protection Agency, *Control of Volatile Organic Emissions from Petroleum Liquid Storage in External Floating Roof Tanks,* 1978.

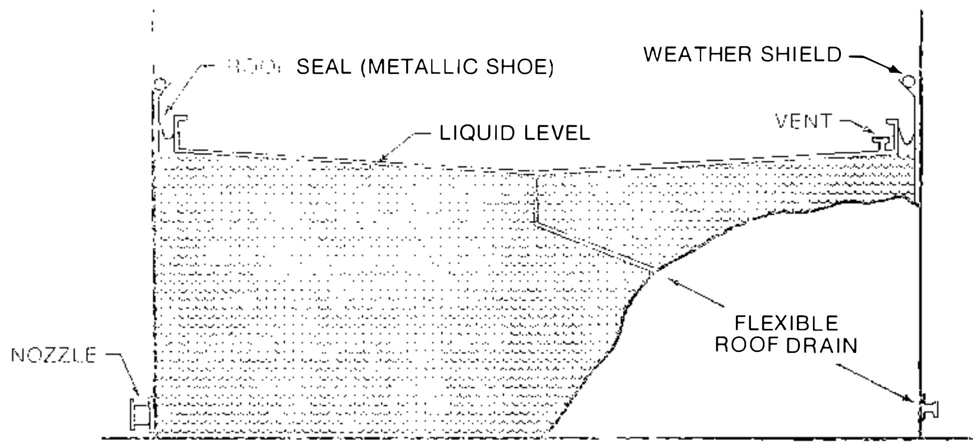


Figure 75. Pan-Type Floating Roof Storage Tank (Metallic Seals).

SOURCE: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Supplement 7, April 1977.

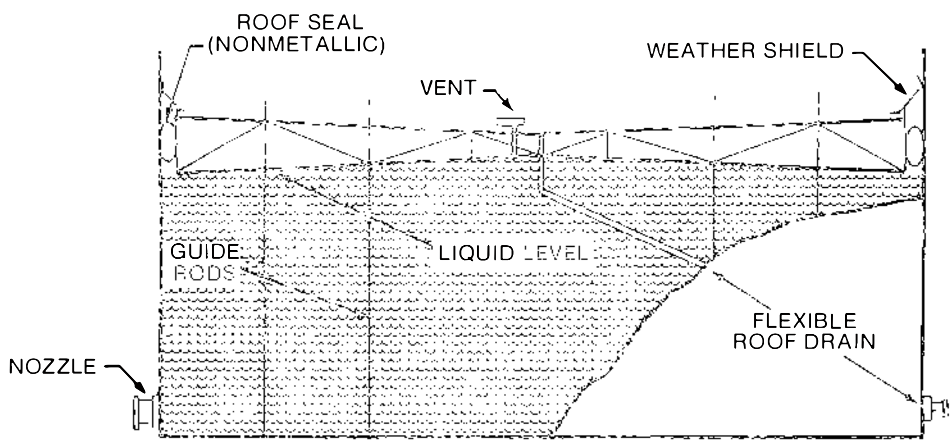


Figure 76. Double-Deck Floating Roof Storage Tank (Nonmetallic Seals).

SOURCE: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Supplement 7, April 1977.

2. Fixed Roof Tanks

A typical fixed roof tank is shown in Figure 77. This type of tank consists of a cylindrical steel shell with a permanently affixed roof, which may vary in design from cone or dome shaped to flat.

Fixed roof tanks are commonly equipped with a pressure/vacuum valve that allows them to operate at a slight internal pressure or vacuum. The pressure/vacuum valves prevent the release of vapors only during very small changes in temperature, pressure, or liquid level. These tanks are generally considered the acceptable standard for storage of petroleum or volatile organic liquids with very low vapor pressures.

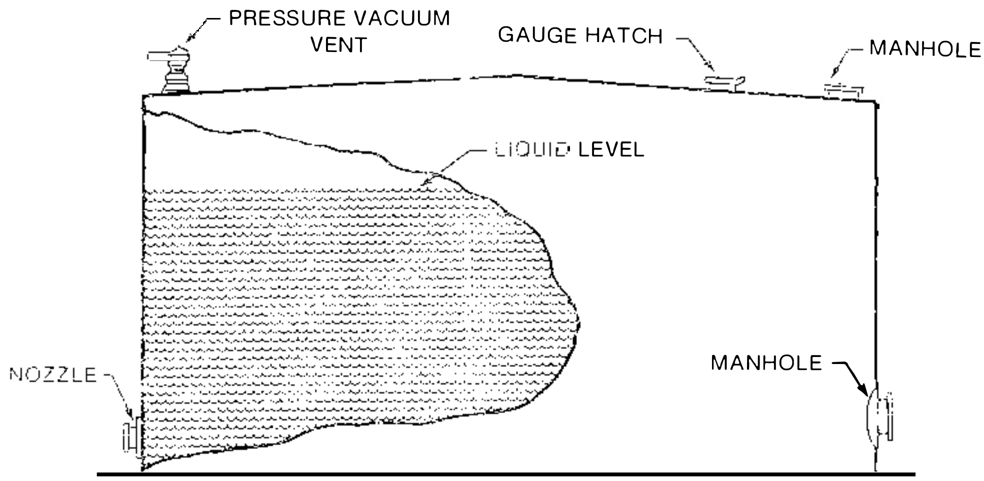


Figure 77. Fixed Roof Storage Tank.

SOURCE: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Supplement 7, April 1977.

3. Internal Floating Roof Tanks

An internal floating roof tank has a permanently affixed roof and an internal deck or roof that floats on the liquid surface (contact roof) or that rests on pontoons several inches above the liquid surface (noncontact roof). Contact roofs include aluminum sandwich panel roofs with a honeycomb aluminum core floating in contact with the liquid, and pan steel roofs floating in contact with the liquid, with or without pontoons. Noncontact roofs typically consist of an aluminum deck or an aluminum grid framework supported above the liquid surface by tubular aluminum pontoons. Both types of roof, as in the case of external floating roofs, commonly incorporate flexible perimeter seals or wipers that slide against the tank wall as the roof moves up and down. In addition, circulation vents and an open vent at the top of the fixed roof can be provided to minimize the possibility of vapor accumulation in concentrations approaching the flammable range. A typical contact internal floating roof tank is shown in Figure 78.

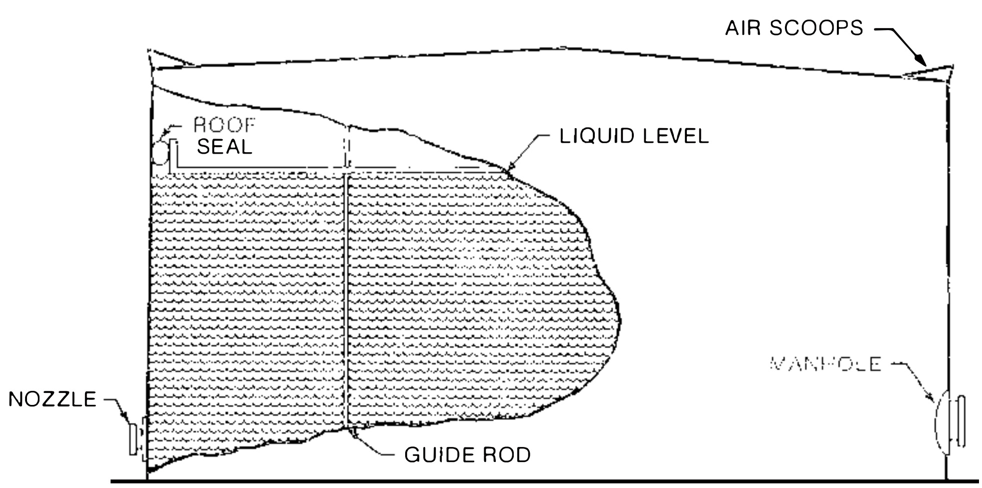


Figure 78. Internal Floating Roof Storage Tank.

SOURCE: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Supplement 7, April 1977.

4. Pressure Tanks

There are two classes of pressure tanks in general use -- low pressure (2-15 psig) and high pressure (up to about 250 psig). Pressure tanks are generally used for storage of liquids with high vapor pressures and are found in many sizes and shapes, depending upon the operating range of the tank (see Table 53).

TABLE 53

Characteristics of Pressure Vessels

Shape of Vessel	Operating Pressures
Horizontal, Cylindrical	Various (depending upon product vapor pressure)
Spheres	Up to 217 psig
Spheroids	Up to 50 psig
Noded Spheroids	Up to 20 psig
Hemispheroids	Up to 15 psig
Noded Hemispheroids	Up to 2.5 psig

5. Variable Vapor Space Tanks

Variable vapor space tanks are equipped with expandable vapor reservoirs to accomodate vapor volume fluctuations attributable to temperature and barometric pressure changes. The two most common types are lifter roof tanks and flexible diaphragm tanks, shown in Figures 79 and 80. Although this type of tank is sometimes used

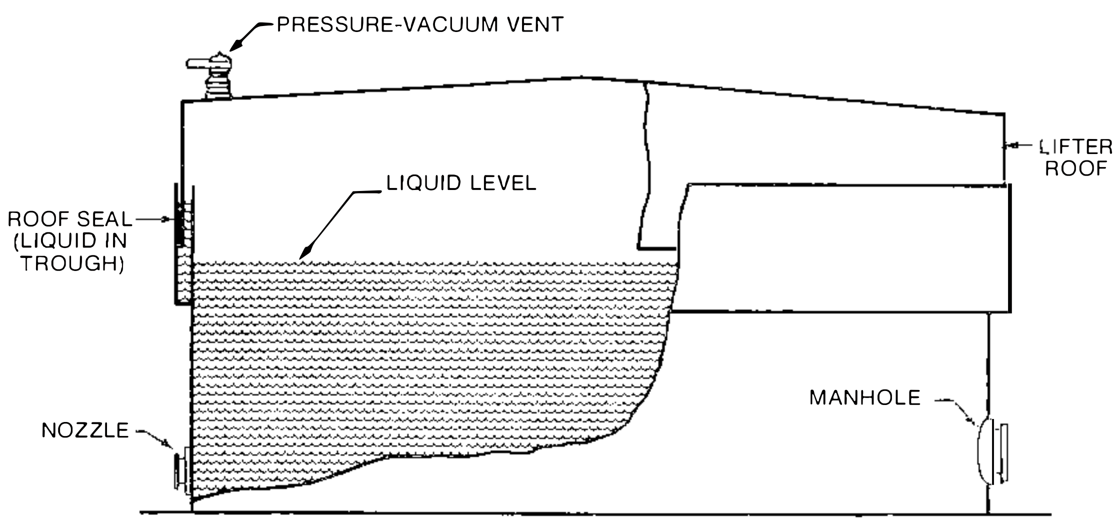


Figure 79. Lifter Roof Storage Tank (Wet Seal).

SOURCE: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Supplement 7, April 1977.

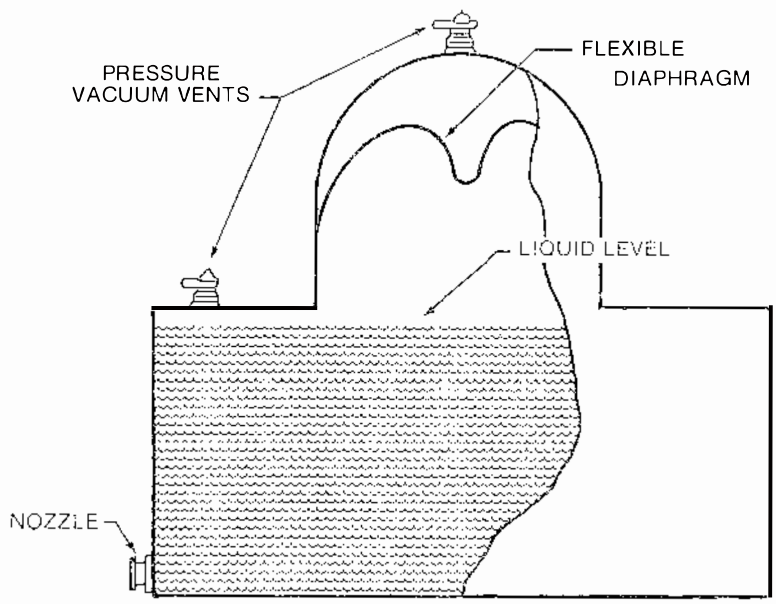


Figure 80. Flexible Diaphragm Tank (Integral Unit).

SOURCE: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Supplement 7, April 1977.

independently, they are normally connected to the vapor spaces of one or more fixed roof tanks.

Lifter roof tanks have a telescoping roof that fits loosely around the outside of the main tank wall. The space between the roof and the wall is closed by either a wet seal, which consists of a trough filled with liquid, or a dry seal, which employs a flexible coated fabric instead of the trough.

Flexible diaphragm tanks use flexible membranes to provide expandable volume. They may be separate gas-holder units or integral units mounted atop fixed roof tanks.

B. Loss Mechanisms

To understand how hydrocarbon vapor losses can occur during storage, it is necessary to introduce the concept of vapor pressure. Every petroleum liquid has a finite vapor pressure that is dependent upon the surface temperature and the composition of liquid. All of these liquids tend to establish an equilibrium concentration of vapors above the liquid surface. Under completely static conditions, an equilibrium vapor concentration is established. However, all tankage is exposed to some degree of dynamic conditions that disturb this equilibrium, leading to additional vaporization. These dynamic conditions are responsible for continued evaporation, resulting in stock loss and atmospheric emissions.

When a volatile liquid is introduced into an air-filled fixed roof tank, a small portion of liquid vaporizes to saturate the vapor space above the liquid. The fraction of hydrocarbon vapor relative to air in the confined vapor space will depend upon the

vapor pressure of the liquid being stored. As air is pulled in through the tank vent, which occurs when the vapor space cools or when liquid is withdrawn from the tank, additional liquid vaporizes to saturate the air introduced. Conversely, saturated vapor is expelled from the tank when the vapor space warms up or when liquid is added to the tank.

Because a floating roof essentially eliminates the vapor space between the liquid surface and the roof, evaporation losses from a floating roof tank will primarily originate from the rim space because of wind induced mechanisms. Wind tunnel tests have shown that the air that flows up and over the top of a floating roof tank produces a low-pressure zone above the roof on the upwind side of the tank. This results in air from the downwind side moving around the circumference of the tank above the rim space. A steady wind thus establishes pressure differentials across the floating roof, with high pressures on the downwind side and lower pressures on the upwind side of the floating roof.[21]

C. Emission Sources and Controls

The emissions from storage tanks occur because of vapor displacement during tank filling, vapor expansion caused by temperature and barometric pressure changes and/or increase in vapor saturation level, wind flow, and/or evaporation from wetted surfaces of the tank. The applicability and impact of these factors depends upon the type of tank and the seal system employed as a control measure. The emission sources and the controls for each of the five types of storage tanks are discussed below.[22]

Table 54 presents a comparison of the emissions from gasoline storage in fixed roof, internal floating roof, and external floating roof tanks with various seal systems.

1. Fixed Roof Tanks

The two types of emissions from fixed roof tanks are breathing losses and working losses. Breathing loss is the expulsion of vapor from a tank due to vapor expansion and contraction from changes in temperature and barometric pressure. It occurs in the absence of any liquid level change in the tank.

The combined loss from filling and emptying is called working loss. Filling loss is associated with an increase of the liquid level in the tank. The vapors are expelled from the tank when the pressure inside the tank exceeds the relief pressure, as a result of filling. Emptying loss occurs when air drawn into the tank during liquid removal becomes saturated with hydrocarbon vapor and expands, thus exceeding the capacity of the vapor space.

Several methods are used to control emissions from fixed roof tanks. One method is installation of an internal floating roof and seals to minimize evaporation of product being stored. The control efficiency of this method ranges from 60 to 92 percent, depending

TABLE 54

Comparison of Emissions from Typical Gasoline Storage Tanks*

Type of Tank and Seal System	Total Annual Emissions† 1,000 lbs/yr	bbl/yr
Fixed Roof	591	2,762
Internal Floating Roof§		
Primary Seal Only	1.4	7
Plus Secondary Seal	0.5	2
External Floating Roof		
Welded Tanks		
Mechanical Shoe Seal	28.1	131
Plus Rim-Mounted Secondary	1.6	7
Liquid-Mounted Resilient Seal	8.1	38
Plus Rim-Mounted Secondary	1.4	7
Vapor-Mounted Resilient Seal	174.8	817
Plus Rim-Mounted Secondary	58.2	272
Riveted Tanks		
Mechanical Shoe Seal	30.5	142
Plus Rim-Mounted Secondary	5.9	28

*Assumptions -- Tank description: 100-foot-diameter tank; shell painted aluminum color. Average vapor space height (fixed roof tank) including roof volume correction = 28 feet. Stored Product: Motor gasoline; Reid vapor pressure, 10 psia; 5.1 lb/gal liquid density; 375,000 barrels throughput for the 3 months. Ambient Conditions: 60°F average ambient temperature for the 3 months; 10 mph average wind speed at tank site for the 3 months; 14.7 psia atmospheric pressure. Average diurnal temperature change 16°F.

†Emissions calculated using factors in the Environmental Protection Agency's Compilation of Air Pollution Emission Factors, Supplement 12, Section 4.3, July 1981.

§It is important to note that EPA has arbitrarily chosen to assume: (a) that seal factors for an external floating roof tank with a liquid-mounted resilient primary seal plus a rim-mounted secondary seal should be used for calculating emissions from an internal floating roof tank having only a primary seal of any type, and (b) that a secondary seal will reduce the standing storage loss by a factor of 4. Industry has not accepted these assumptions, pending results of an API testing program scheduled for completion in late 1981.

upon the type of roof and seals installed and on the type of product. The following section discusses the internal floating roof tank in more detail.

Another control method, the vapor recovery system, collects emissions from storage vessels and converts them to liquid product. Several vapor recovery precedures may be used, including vapor/liquid absorption, vapor compression, vapor cooling, vapor/solid adsorption, or a combination of these. The overall control efficiencies of vapor recovery systems depend upon the method used, the design of the unit, the composition of vapors recovered, and the mechanical condition of the system. If the collected vapors are not to be converted to liquid or recycled, they can be disposed of by thermal oxidation (incineration).

2. Internal Floating Roof Tanks

An internal floating roof tank generally has the same sources of emissions as an external floating roof tank: withdrawal loss and standing storage loss. Fitting losses, from penetrations in the roof by deck fittings, roof column supports, or other openings, can also contribute to the emissions.

Because of structural considerations, the type of primary seal used to reduce emissions depends upon the type of floating roof. If the roof is aluminum, usually only a small, vapor-mounted wiper seal is installed. However, with a steel deck, any of the seals used with external floating roofs can be satisfactorily employed.

Tank diameter also must be considered. Although internal floating roofs are now in use in tanks with a nominal 10-foot diameter, special designs and installations are necessary. Twenty feet is the practical minimum diameter.

3. External Floating Roof Tanks

The two types of emissions from external floating roof tanks are standing storage losses and withdrawal losses. Standing storage loss results from wind-induced mechanisms as air flows across the top of the external floating roof tank. Withdrawal loss is the vaporization of the liquid that clings to the tank wall and is exposed to the atmosphere when a floating roof is lowered by withdrawal of liquid. The withdrawal loss is usually insignificant in comparison to the standing storage loss, but should be considered in developing total loss quantities.[23]

Penetrations such as roof fittings and access parts through the floating roof are another potential source of evaporative loss, but when these penetrations are liquid-sealed or closed, the losses are negligible. If a tank is completely emptied, such that the underside of the roof is exposed to air, additional evaporative loss will result when the tank is subsequently filled.

Because the primary route of the emissions from the surface of the stored liquid to the atmosphere is from the rim space between

the floating roof and the tank shell, the seal system and its condition are critical emission control factors. An external floating roof tank seal system can consist of one or two separate seals. The first seal is called the primary seal, and the second seal, mounted above the primary seal, is called the secondary seal.

Three basic types of primary seals are currently in widespread use. These primary seals can be classified as mechanical (metallic) shoe, resilient (nonmetallic) filled, and flexible wiper. Two basic configurations of secondary seals are currently available: shoe-mounted and rim-mounted. In addition, some seal systems include a weather shield. Other types of primary and secondary seals have been or are currently being developed but are not presently in widespread use.

4. Pressure Tanks

High-pressure storage tanks can be operated so that virtually no evaporative or working losses occur. Working losses can occur in low-pressure tanks due to atmospheric venting of the pressure tank during filling and withdrawal operations, and vapor recovery systems are thus sometimes used.

Fugitive losses are also associated with pressure tanks and their equipment, but with proper system maintenance these losses are considered insignificant.

5. Variable Vapor Space Tanks

Variable vapor space filling losses result when vapor is displaced by liquid during filling operations, but because the tank has an expandable vapor storage capacity this loss is not as large as the filling loss associated with fixed roof tanks, and loss of vapor occurs only when the vapor storage capacity of the tank is exceeded.

IV. Transportation Emissions

The hydrocarbon emissions associated with the transportation of petroleum liquids occur primarily during the loading of delivery vessels. Losses due to temperature and barometric pressure change during transit and losses during manual tank gauging of marine vessel compartments are negligible.

Rail tank cars and pipelines are also important transportation methods but have minimal emissions. In fact, EPA has suspended development of a CTG for railcars. Similarly, there are no regulations for control of hydrocarbon emissions specifically from pipelines because the lines compose a completely closed system and any significant emissions can occur only in an abnormal situation such as a break or a leak. These occurrences are minimized by the constant surveillance system described in the Industry Operations section of this chapter.

The other potential emission source from pipeline operations is the exhaust from the engines used to drive the pumps at the pumping stations along the line. Most of these pumps are now electrically powered but some can be diesel fueled, creating a relatively small source of NO_x emissions.

A. Tank Truck Emissions[24]

Hydrocarbon emissions from tank trucks primarily occur during gasoline loading at marketing terminals and bulk plants. Other truck-carried high-volume products, such as fuel oil, have a low vapor pressure, thus there are no significant emissions or need for controls. Under some conditions in transit, a negligible quantity of vapor may escape through the pressure/vacuum relief valve found on each compartment of a truck. The occurrence of these leaks is minimized, however, by the annual leak-tight testing requirement that now must be incorporated in SIPs.

Without emission controls on the loading operation, the quantities of vapors emitted depend upon the loading method used and the concentration of the vapors in the truck compartments at the start of loading.

The two basic methods of filling tank trucks are splash loading and submerged loading. In the splash loading method (Figure 81), the fill pipe dispensing the gasoline is only partially lowered into the compartment. Significant turbulence and vapor/liquid contacting occurs, resulting in high levels of vapor generation and loss. If the turbulence is great enough, liquid droplets will be entrained in the vapors and vented to the atmosphere through the open hatch.

There are two types of submerged loading: the submerged fill pipe method and the bottom loading method. In the submerged fill

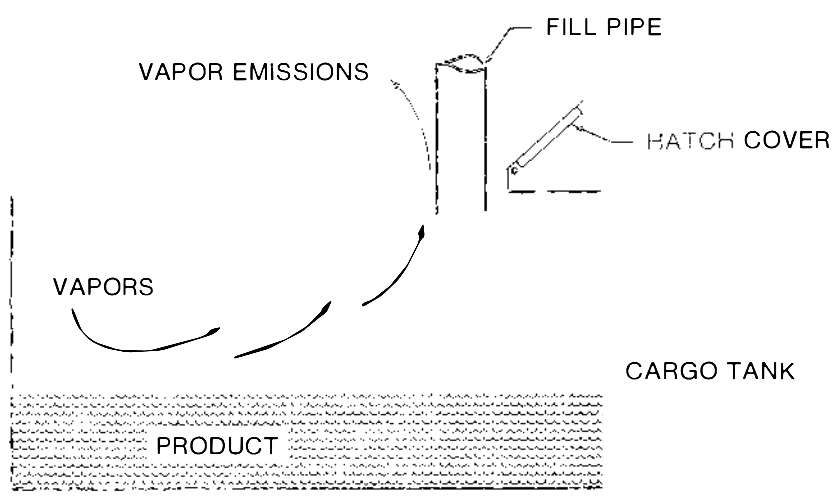


Figure 81. Top Loading Method Without Vapor Collection—Top Splash Loading.

SOURCE: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Supplement 7, April 1977.

pipe method (Figure 82), the fill pipe descends almost to the bottom of the compartment. In the bottom loading method (Figure 83), the transfer piping is connected directly to the compartment bottom. During the major filling portion of the submerged fill method, and the entire portion of the bottom loading method, the fill pipe opening is positioned below the liquid level. The submerged loading method significantly reduces liquid turbulence and vapor/liquid contacting, thereby resulting in much lower hydrocarbon losses than encountered during splash loading. Also, bottom loading has the additional advantages of safety and ease of loading.

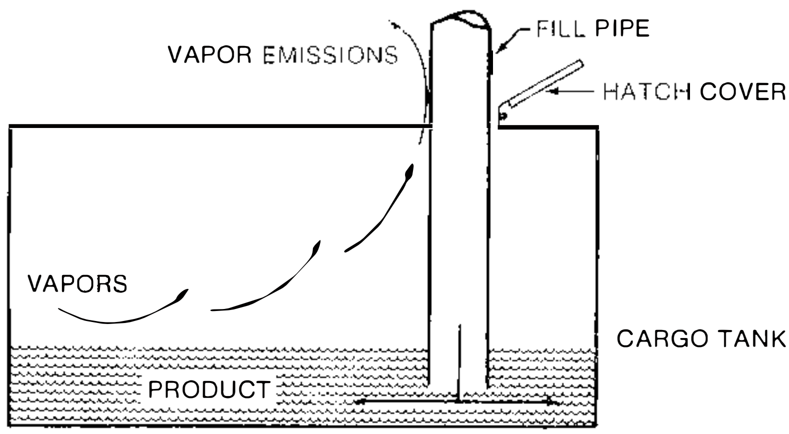


Figure 82. Top Loading Method Without Vapor Collection—Top Submerged Loading.

SOURCE: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Supplement 7, April 1977.

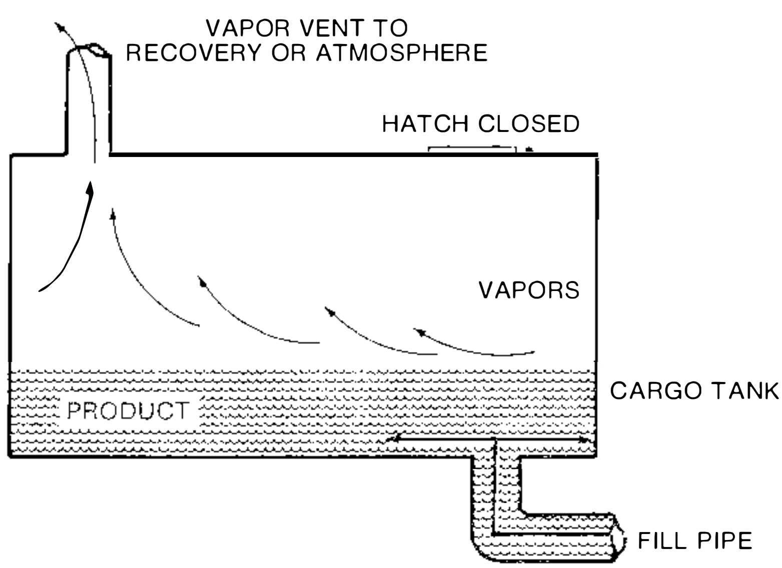


Figure 83. Bottom Loading Method.

SOURCE: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Supplement 7, April 1977.

The use history of the truck is just as important a factor in loading losses as the method of loading. Hydrocarbon emissions are generally lowest from a truck whose compartments are free from vapors prior to loading. Clean tanks normally result when the previous haul carried a nonvolatile liquid, such as diesel or light fuel oils.

A truck that is dedicated to the transport of only one product will retain a low but significant concentration of vapors in its compartments. These residual vapors were generated by evaporation of residual product on the tank surfaces and are expelled along with newly generated vapors during the subsequent loading operation.

Another type of truck is one in vapor balance service. These trucks pick up vapors displaced from the storage tanks being filled during unloading operations and transport these vapors in the empty compartment tanks back to the loading terminal. These vapors normally approach the saturation level of hydrocarbon concentration.

The emissions for uncontrolled splash loading are 12 pounds per 1,000 gallons. For the submerged fill pipe or bottom loading, the emissions are reduced to 5 pounds per 1,000 gallons. These factors apply to normal service in which the tank trucks do not vapor balance at the delivery points. When vapor balancing is employed, the vapors displaced from the truck during loading at the terminal are controlled by a processing system that reduces the emissions to 1 pound per 1,000 gallons, or less.[25]

Three basic methods exist for reducing emissions from uncontrolled, top splash loading of tank trucks: submerged loading as discussed in the preceding section; vapor balancing; and collection and recovery or disposal of the vapor displaced from the tank truck during loading. The vapor balancing technique is only feasible for bulk plants where floating roof tanks are not normally used. Vapor recovery units can be used at both bulk plants and terminals but usually are installed only at terminals because the units cannot be economically justified for the lower throughput of the bulk plants.

1. Vapor Balancing At Bulk Plants

Bulk plants are typically secondary distribution facilities that receive gasoline from terminals by tank trucks, store it in above-ground storage tanks, and subsequently dispense it via account trucks to local farms, businesses, and service stations. A typical bulk plant has a throughput of 4,000 gallons of gasoline per day with storage capacity of about 50,000 gallons of gasoline. EPA defines the bulk plant as having a throughput of less than 20,000 gallons of gasoline per day averaged over the work days in one year.[26]

The vapor balance system operates by transferring vapors displaced from the receiving tank to the tank being unloaded. A vapor

line between the truck and the storage tanks essentially creates a closed system permitting the vapor spaces of the two tanks to balance with each other. Figure 84 shows a typical flow scheme of a vapor balance system.

Vapor balancing with incoming tank trucks displaces vapor from the storage tanks to the truck compartments; the collected vapors are recovered or disposed of at the terminal. EPA-sponsored tests have shown that a vapor balancing efficiency greater than 90 percent is attainable with the tank trucks and storage tanks.

Vapor balancing of storage tanks and account trucks reduces account truck filling losses by 90 percent or more. Balancing during account truck filling virtually eliminates withdrawal losses from the storage tanks, since the air displaced from the truck to the tank is saturated or nearly saturated with hydrocarbons. The efficiency attainable in loading account trucks is strongly affected by the tightness of the truck compartments (i.e., condition of hatches and seals) and by the care exercised in making connections.

2. Vapor Recovery/Disposal at Terminals[27]

a. Vapor Collection

The effectiveness of a vapor control system for truck loading at a terminal is as dependent upon the efficient collection and transfer of the displaced vapors to the processing unit as it is upon the performance of the vapor processing unit. The typical system consists of the connections, piping, and other equipment necessary to safely transfer the hydrocarbon vapors from the tank trucks to the vapor processor. The major system components are the top or bottom loading connections to the trucks, the liquid knockout tank, the saturator tank, and the vapor holder.

For top loading, a vapor head, compatible with the truck hatch opening, creates a vapor-tight seal between the loading head and the hatch to minimize vapor leakage during loading. An annular space in the vapor head provides the route for the vapors from the compartment into the vapor line, then into the vapor collection system (see Figure 85).

In a top tight submerged fill installation, the loading of product is performed through a vapor-tight loading adapter mounted on top of each compartment and attached to a permanently fixed submerged fill pipe. One advantage of this permanently affixed top tight submerged fill system over the top loading vapor head system is that the hatch/dome covers remain closed during loading. Figure 86 shows one of these configurations. Vapor collection with this installation uses the same technique as bottom loading, which is described below.

The top tight loading system is not in widespread use at terminals. Simplified loading combined with vapor collection is generally accomplished using bottom loading.

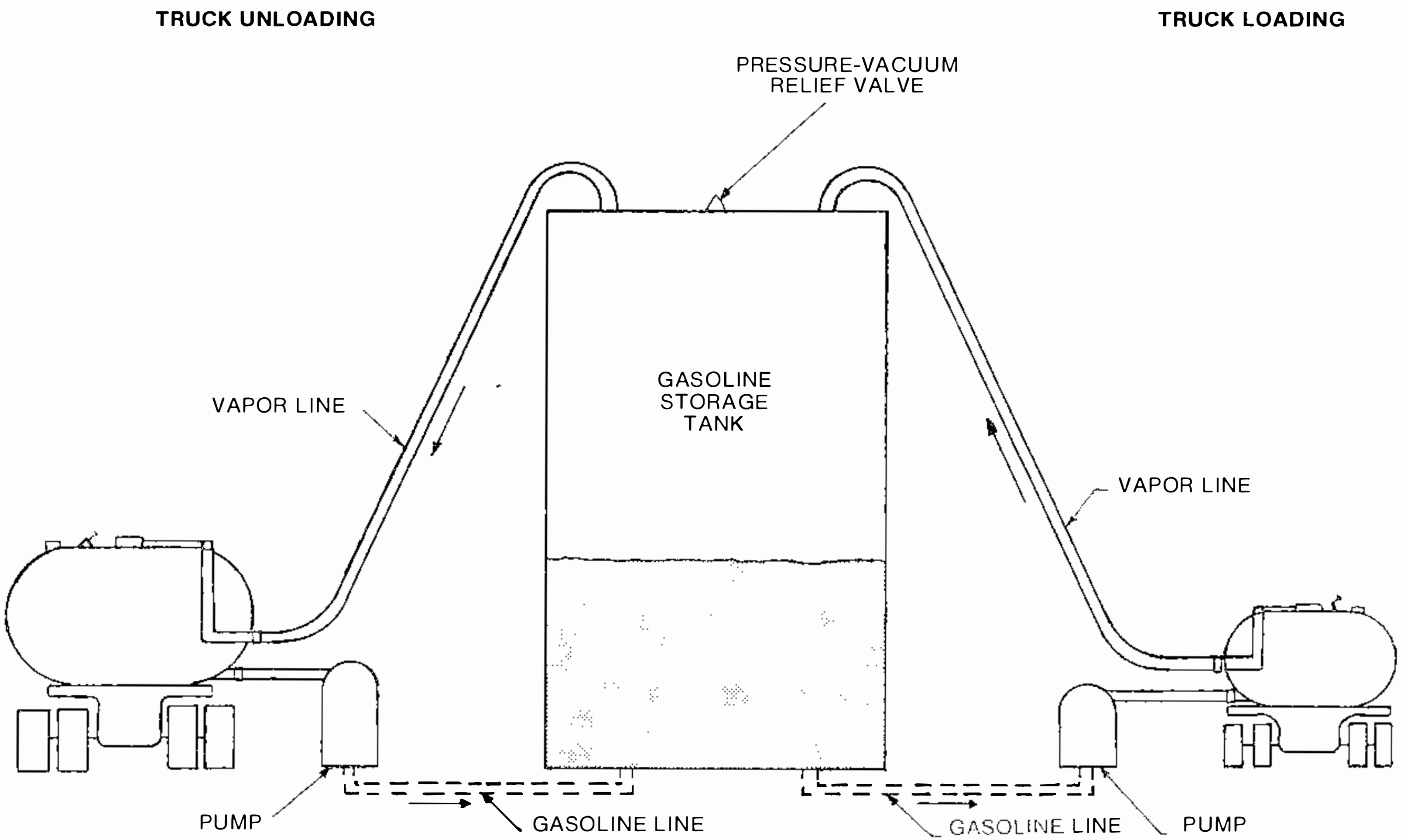


Figure 84. Vapor Balance System at a Bulk Plant—Bottom Fill.

SOURCE: Environmental Protection Agency, *Control of Volatile Organic Emissions from Bulk Gasoline Plants*, December 1977.

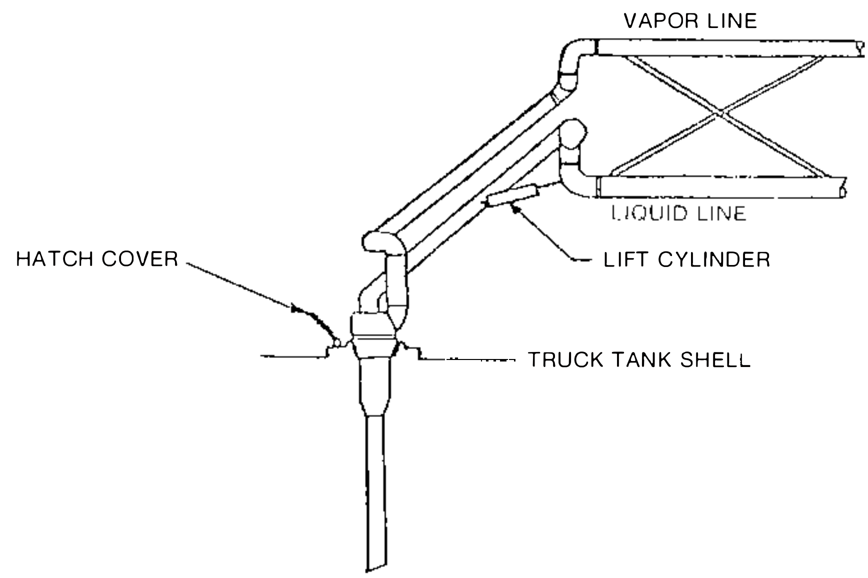


Figure 85. Top Loading Systems with Vapor Collection—Top Loading Vapor Head System.

SOURCE: Environmental Protection Agency, *Control of Volatile Organic Emissions from Bulk Gasoline Plants*, December 1977.

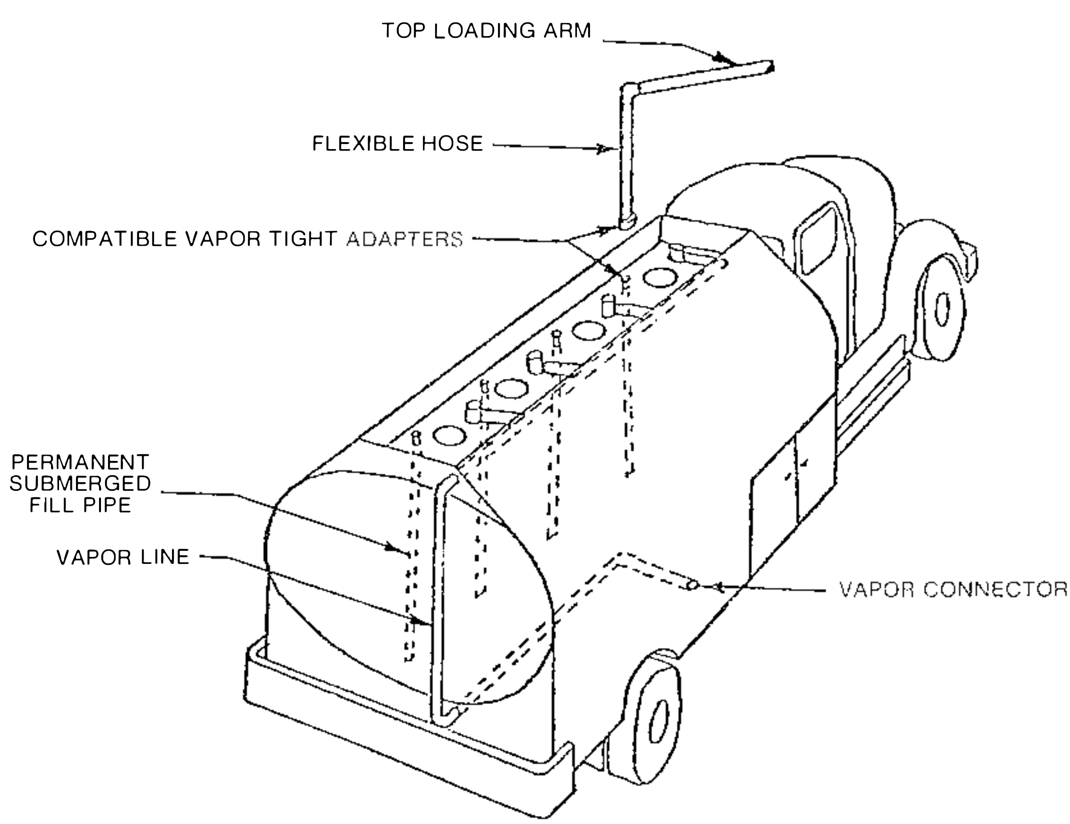


Figure 86. Top Loading Systems with Vapor Collection—Top Tight Submerged Fill.

SOURCE: Environmental Protection Agency, *Control of Volatile Organic Emissions from Bulk Gasoline Plants*, December 1977.

Bottom loading is accomplished through valves in the bottom of each compartment that are piped to dry-break couplers. The couplers are used to attach loading arms or hoses to the trucks so that liquid loss can be minimized during connecting and disconnecting. For vapor collection, a flexible hose or swing-type arm is connected to a vapor collection manifold on the truck. A typical bottom loading system is shown in Figure 87.

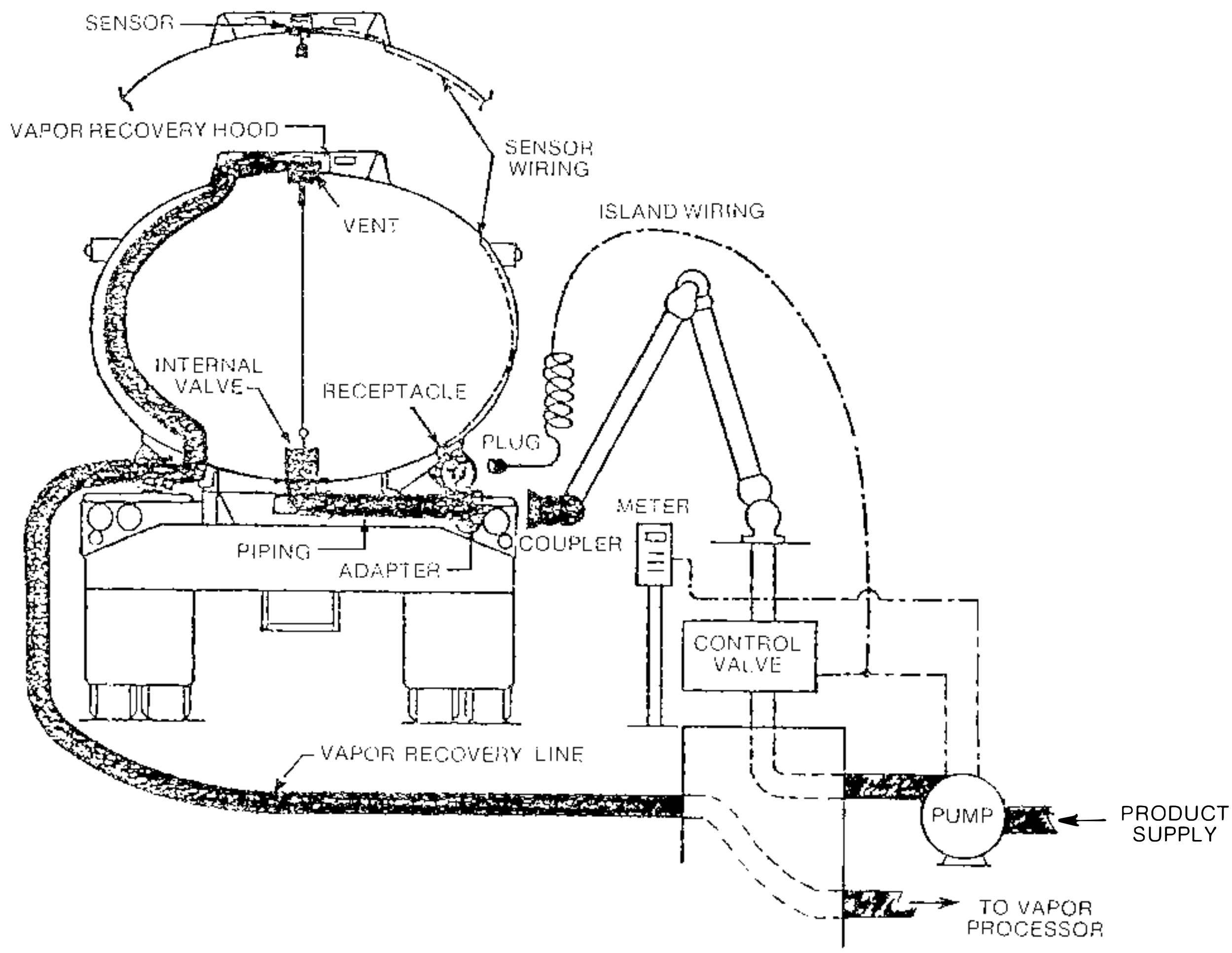


Figure 87. Typical Bottom Loading System with Vapor Collection.

NOTE: Actual physical connections for loading and removing vapors are side-by-side.

SOURCE: Environmental Protection Agency, *Control of Volatile Organic Emissions from Bulk Gasoline Plants*, December 1977.

During the bottom loading operation, an internal valve is opened to allow product flow, and tank vent valves on top of the truck are opened to permit the exit of vapors that are displaced by the incoming product. The vent valves are hooded and usually connected to the truck overturn rail that then serves as the vapor manifold. The manifold is connected to the tank truck vapor line, which terminates at a connector on the side or at the rear of the truck and is compatible with the terminal vapor collection equipment. Details of the top of a truck compartment are shown in Figure 88.

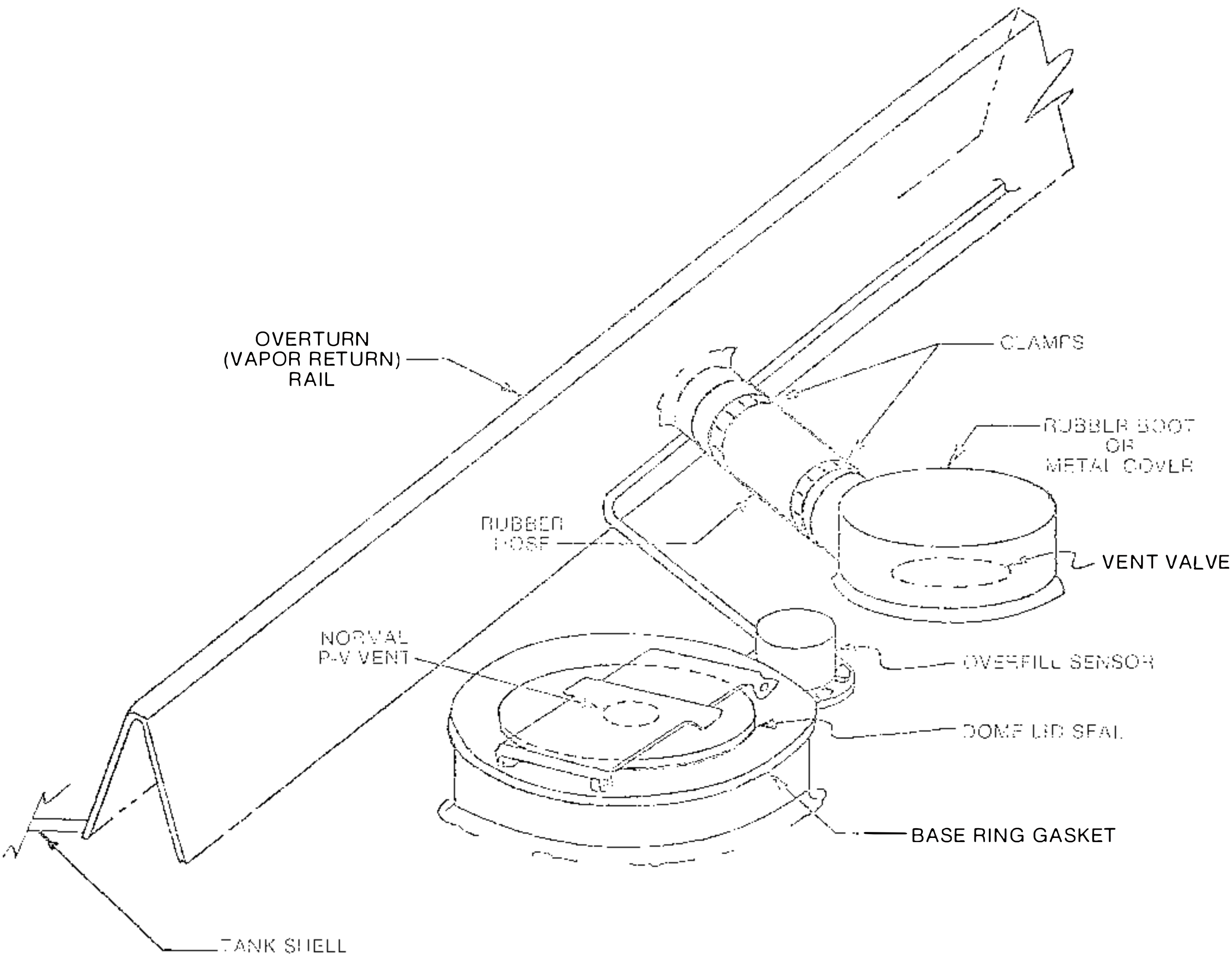


Figure 88. Details of the Top of a Truck Compartment.

SOURCE: Environmental Protection Agency, *Control of Volatile Organic Emissions from Bulk Gasoline Plants*, December 1977.

In order to measure the quantity of gasoline delivered during bottom loading and to provide protection against overfilling, set-stop meters are used to shut off the flow of gasoline when a pre-set quantity has been delivered. Liquid-level sensing devices are commonly used with pre-set meters to provide secondary control in event of a malfunction or human error. The sensors are devices used to detect a full condition in the compartment being loaded. They are electrically connected to close flow control valves or shut off the delivery pumps if the level approaches the top of the tank, which eliminates the possibility of overfilling the compartment. Commonly used sensing devices include fiber optics systems, electric probes, and float switches.

Three other components may be included in some vapor collection systems between the loading racks and the processor: the liquid knockout tank, the saturator tank, and the vapor holder.

The liquid knockout tank removes liquid gasoline from the vapor line between the loading rack and the processor and stores it for subsequent recovery or disposal. Liquid can enter the vapor line due to accidental overfilling or can form in the line under certain ambient conditions.

Saturator tanks contain gasoline sprays to raise the vapor concentration above the explosive range. Saturation spraying is also used in conjunction with vapor holders and as a first stage in some vapor processing systems.

Vapor holders store the air/vapor mixture generated at the loading racks until some pre-set capacity is reached, and then they release it to the vapor processor. Thus, fluctuations in the vapor volume are minimized, the vapors are processed on a batch basis rather than running the processor continuously, and the processor can be sized for less than peak truck-loading periods. Generally, a vapor holder consists of a large tank containing a flexible bladder that is equipped with a level sensor. Saturator tanks and vapor holders are not used with all types of vapor processing units.

b. Vapor Processing

The vapor processing unit can either recover or destroy the hydrocarbon vapors routed to the unit from the tank trucks via the vapor collection system The six basic types of units currently in use in the United States are: thermal oxidation, carbon adsorption, refrigeration, compression-refrigeration-absorption, compression-refrigeration-condensation, and lean oil absorption. Thermal oxidation, or incineration, is the only approach that destroys the collected vapors. The others all recover the gasoline vapors as liquid gasoline.

The control efficiency of the currently marketed units has been shown to be above 90 percent. However, the environmental regulations usually state the performance requirements in terms of the amount of hydrocarbon vapor that can be emitted from the system per unit of volume of product loaded. Specifically, the EPA maximum allowable emission from a terminal unit is 80 milligrams of hydrocarbon per liter of gasoline loaded. In December 1980, EPA proposed that new or modified terminals meet a lower limit of 35 milligrams per liter (mg/l). These NSPS are under review by EPA and have not been issued. LAER limits have been set at 30 mg/l.

The carbon adsorption and refrigeration concepts are relatively new for terminal units, having been put into operation since 1974. The other types have been used at terminals and at other points in the petroleum industry and elsewhere for many years. Descriptions and schematic diagrams of each of the basic types of vapor processing units are presented on the following pages.

(i) Thermal Oxidation

The thermal oxidation control unit relies on burning the vapor (using a pilot flame) to produce nonpolluting combustion products. In this system no gasoline is recovered.

Vapors from the loading racks are piped either to a vapor holder or directly to the oxidizer unit. When a vapor holder is used, operation of the oxidizer begins when the holder reaches a pre-set level, and ends when the holder is empty. With no vapor holder in the system, the oxidizer is energized by means of pressure in a vapor line, indicating that tank truck loading is in progress, or by an electrical signal produced by a manual activation at the loading rack. In some cases propane is injected into the vapor stream to keep the hydrocarbon concentration level above the explosive range.

Other equipment included in thermal oxidation systems are flame arrestors to prevent flashback from the unit to the loading area, and in some later models an isolating valve to prevent vapor flow under low-pressure conditions. Figure 89 shows a simplified schematic diagram of a thermal oxidation system.

Thermal oxidation units have the advantages of low capital cost, simplicity of design, and high processing efficiency. A disadvantage is that they do not recover gasoline vapors as liquid product.

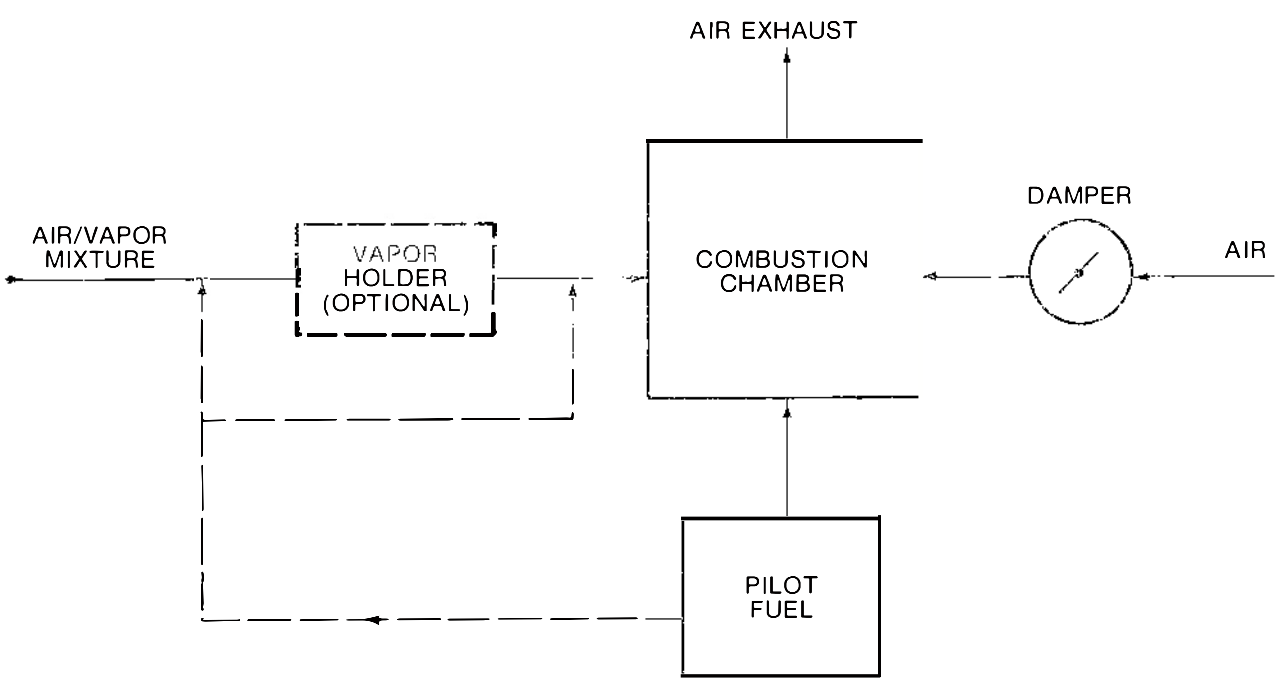


Figure 89. Schematic Diagram of a Thermal Oxidation System.

SOURCE: Environmental Protection Agency, *Background Information Document for the New Source Performance Standards*, December 1980.

Some recently developed control systems consist of a compression-aftercooler stage to recover most of the displaced vapors as liquid gasoline, followed by a thermal oxidation stage to reduce hydrocarbon emissions to the required level. These systems provide one option for recovering some product while achieving the high control efficiency of the thermal oxidation approach.

(ii) Carbon Adsorption

The carbon adsorption vapor recovery system uses beds of activated carbon to remove the hydrocarbons from the air/vapor mixture collected from the truck loading operation. These units generally consist of two vertically positioned carbon beds and a carbon regeneration system. During gasoline tank truck loading activity, one carbon bed is in the adsorbing mode while the other bed is being regenerated. Vapors from the loading racks enter the base of one of the adsorption columns and are adsorbed onto the activated carbon as the gases ascend. Adsorption in one carbon bed occurs for a specific timed cycle before switchover to regeneration (desorption) occurs. The nearly saturated carbon bed is then subjected to vacuum, steam, or thermal regeneration, or a combination of these methods, and the hydrocarbons are stripped from the bed. Vacuum-regenerated units recover the hydrocarbons by absorption in a gasoline stream which circulates between the control unit and gasoline storage. The air and any remaining hydrocarbons exiting from the absorber are passed again through the adsorbing bed, and are then exhausted to the atmosphere. Steam regenerated units condense the hydrocarbon/water mixture, which results from steam stripping the carbon bed, and return the separated product to storage. Some vacuum regenerated systems remain in the regeneration mode for up to two hours after loading activity ceases, in order to remove any residual vapors in the system and to assure complete regeneration of the carbon beds. Figure 90 shows a simplified schematic diagram of an activated carbon adsorption system.

(iii) Refrigeration

Refrigeration-type recovery units remove the hydrocarbons from the air/vapor mixture by low-temperature refrigeration at atmospheric pressure. Vapor displaced from tank trucks enters a condenser section where the temperature is below the dew point of gasoline. The hydrocarbons are condensed and collected, while water vapor freezes on the condenser tubes. During the defrost cycle, the ice melts and the water is collected with the gasoline. The gasoline is then decanted and returned to storage or is injected into a truck loading line.

On many refrigeration units the defrost cycle is performed during periods of no loading activity since the unit cannot collect hydrocarbons during the defrost cycle. Some units, however, contain a double set of heat recovery and low-temperature coils over which the vapor is alternately passed. Newer refrigeration units directly refrigerate the condenser coil collection surfaces, thus eliminating the chilled brine. Figure 91 shows a simplified schematic diagram of the refrigeration system.

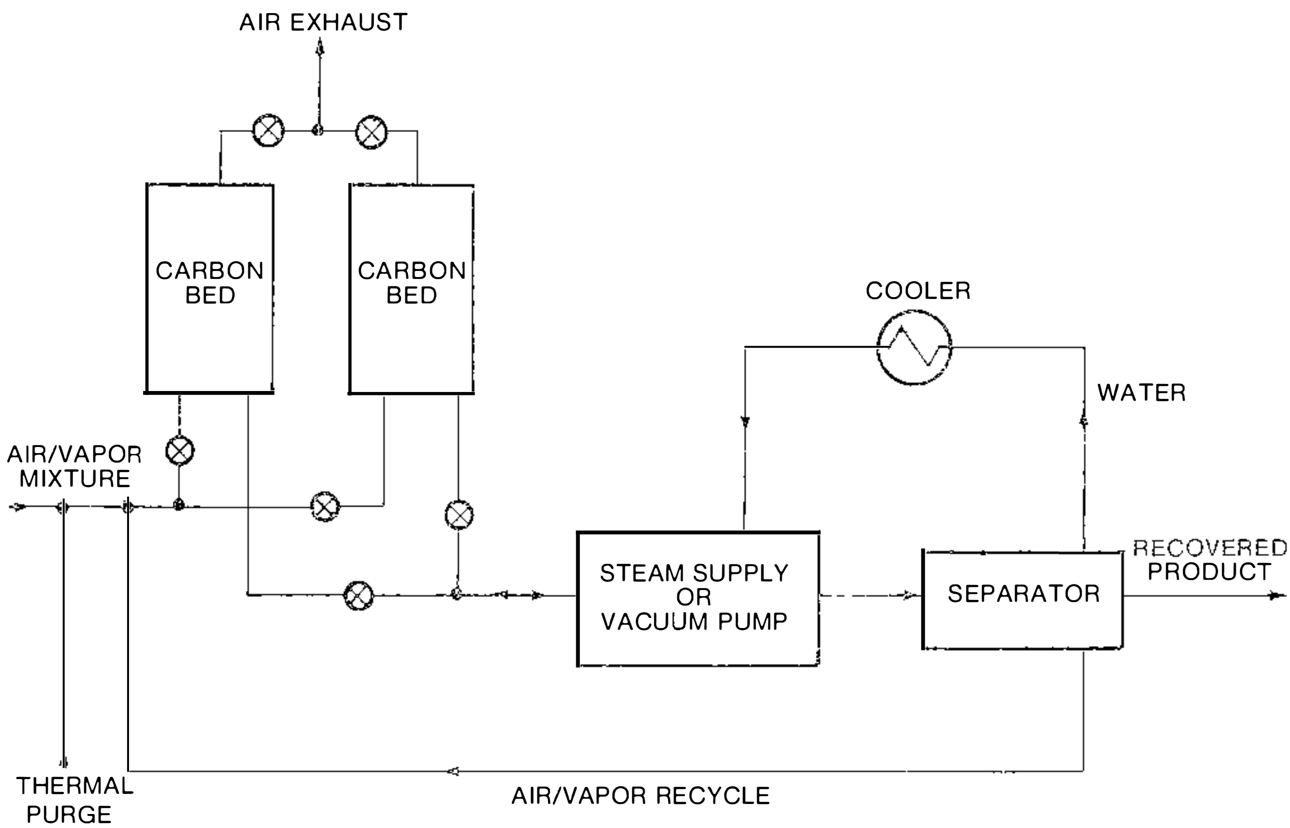


Figure 90. Schematic Diagram of a Carbon Adsorption System.

SOURCE: Environmental Protection Agency, *Background Information Document for the New Source Performance Standards*, December 1980.

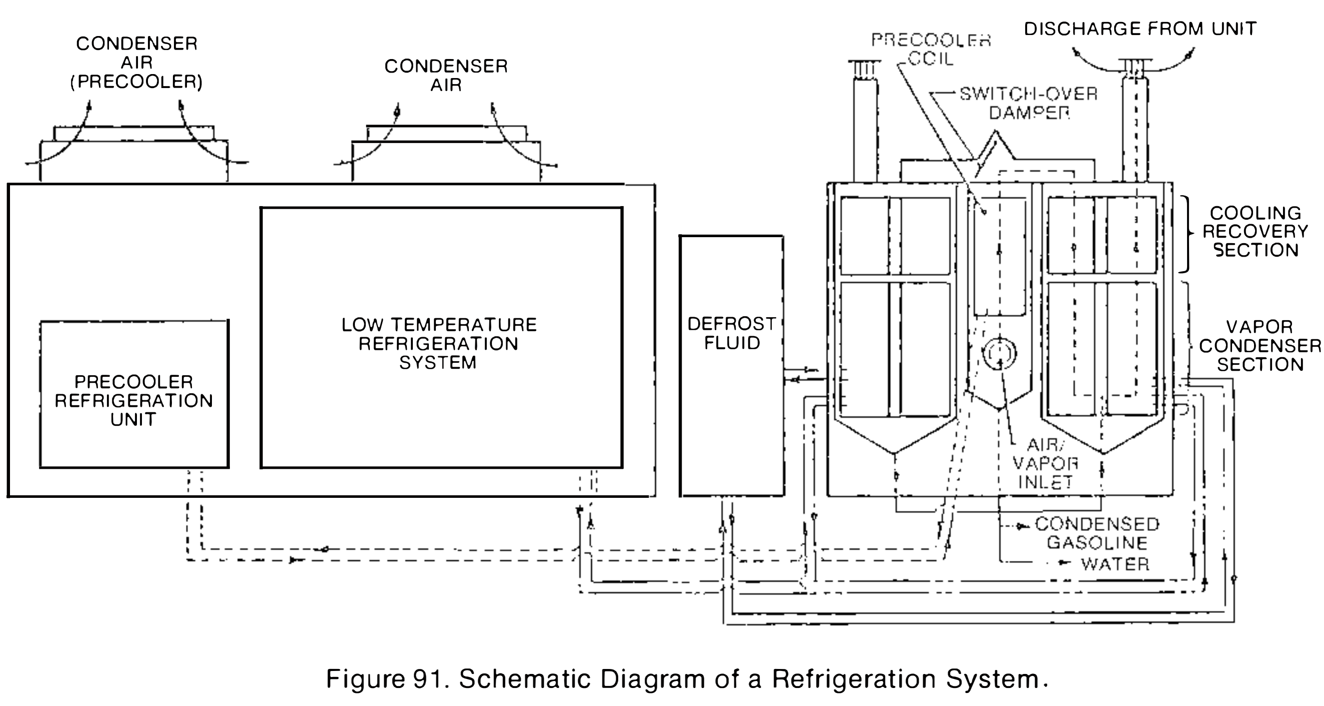


Figure 91. Schematic Diagram of a Refrigeration System.

SOURCE: Edwards Engineering Corp., Pompton Plains, New Jersey.

(iv) Compression-Refrigeration-Absorption

In a compression-refrigeration-absorption vapor recovery unit, the vapors from the loading racks are first passed through a saturator that sprays liquid gasoline into the air/vapor stream. The saturated vapor mixture is stored in a vapor holder until, at a pre-set level, it is released to the control unit.

The first stage of processing is a compression-refrigeration cycle in which water and heavy vapors are compressed, cooled, and condensed. The uncondensed vapors move into an absorber column, where they are contacted and absorbed by gasoline (4°C or 39°F) that has been chilled by the refrigeration unit. The operation of the vapor recovery unit is intermittent, starting when the vapor holder is filled and stopping when it has emptied. Cleaned gases are vented from the absorber column to atmosphere. A simplified schematic diagram of a typical compression-refrigeration-absorption system is shown in Figure 92.

(v) Compression-Refrigeration-Condensation

A vapor recovery system employing a compression-refrigeration-condensation unit also makes use of a vapor holder to store accumulated air/vapor mixture, and a saturator for ensuring that the vapor concentration is above the explosive range. The unit is

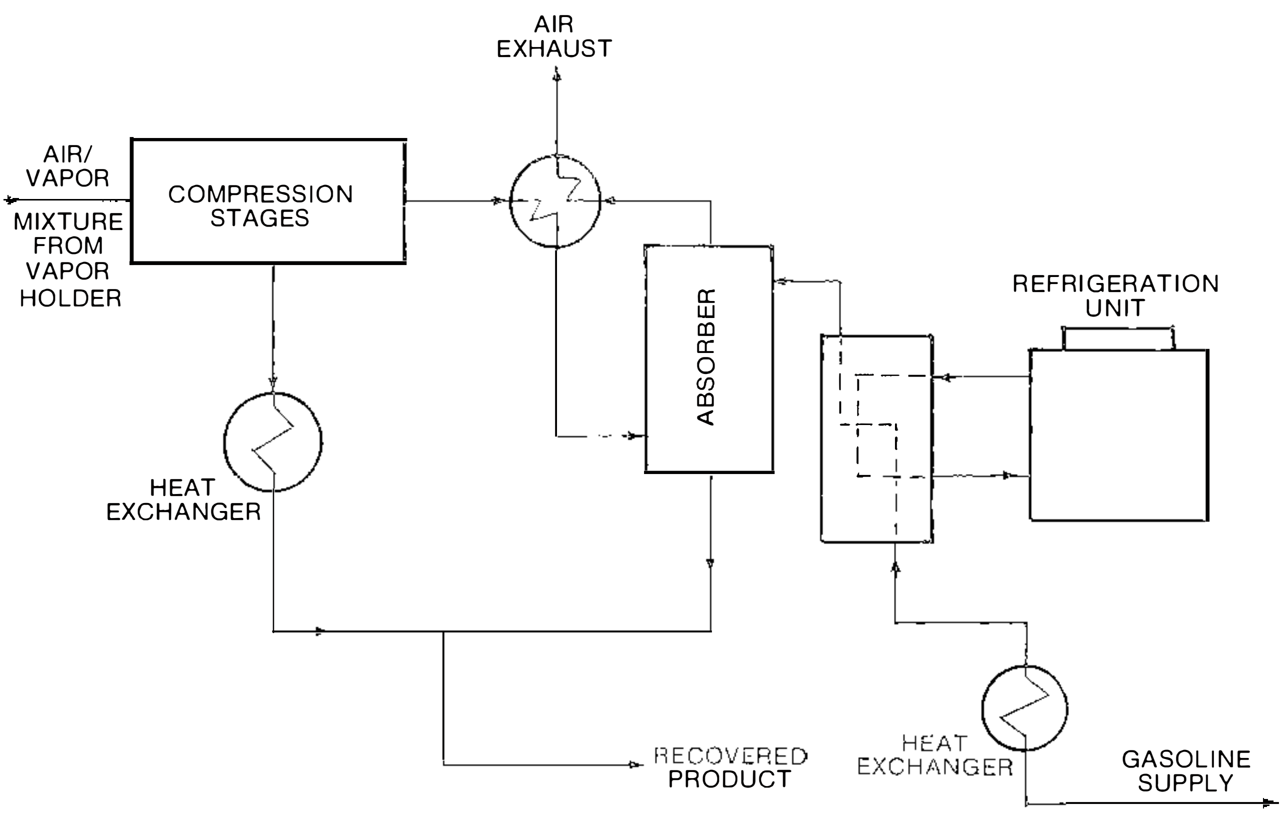


Figure 92. Schematic Diagram of a Compression-Refrigeration-Absorption System.

SOURCE: Environmental Protection Agency, *Background Information Document for the New Source Performance Standards*, December 1980.

activated and begins processing vapors when the vapor holder has filled to a pre-set level.

Incoming saturated air/vapor mixture is first compressed in a two-stage compressor with an intercooler. Condensate is withdrawn from the intercooler to further compress the air/vapor mixture in the second stage. The compressed vapors then pass through a refrigeration-condenser section where they are returned with the intercooler condensate to a gasoline storage tank. Cleaned gases are exhausted from the top of the condenser. Figure 93 shows a simplified schematic diagram of a compression-refrigeration-condensation system.

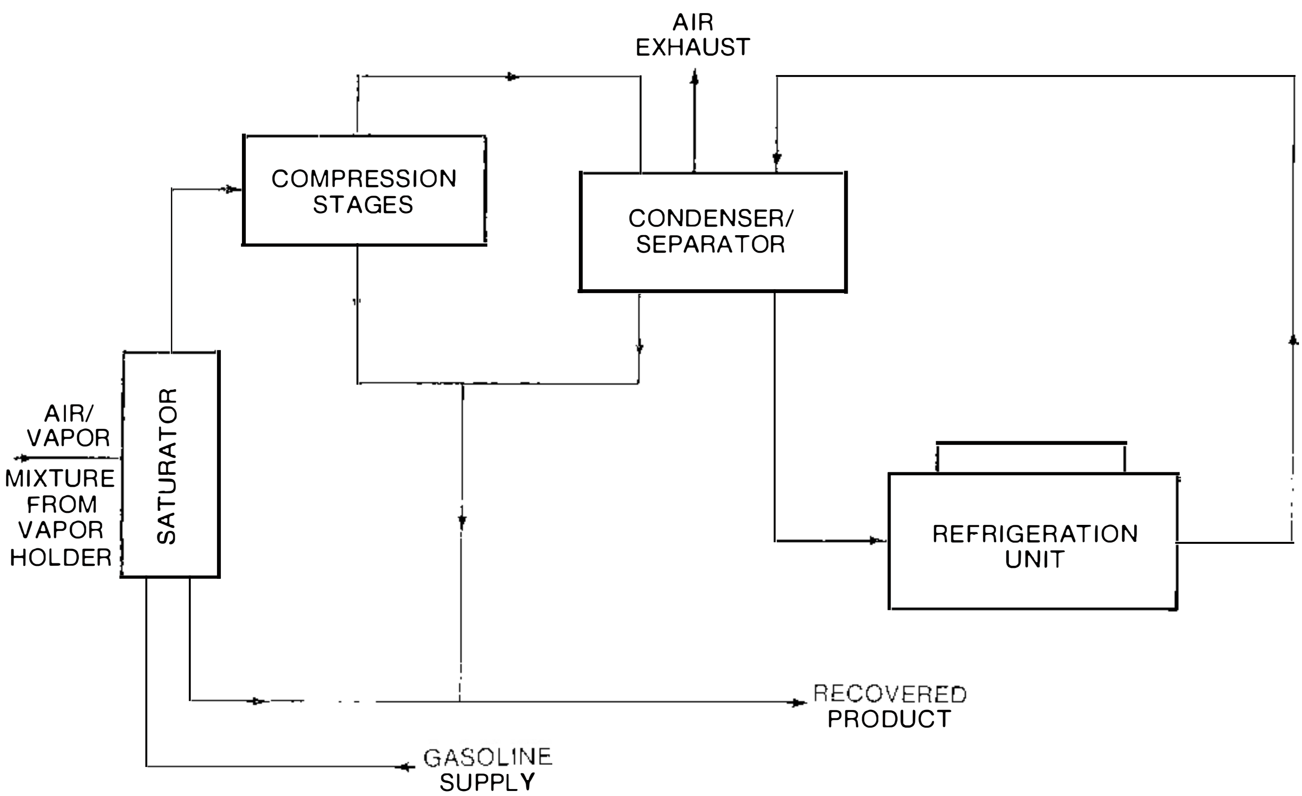


Figure 93. Schematic Diagram of a Compression-Refrigeration-Condensation System.

SOURCE: Environmental Protection Agency, *Background Information Document for the New Source Performance Standards,* December 1980.

(vi) Lean Oil Absorption

The lean oil absorption unit relies on the absorption of the vapors in a lean oil that may be a middle distillate, or gasoline from which the light components have been previously removed. In this unit, vapors enter the base of an absorber column and create a pressure differential across an orifice mounted at the inlet. The differential creates a signal proportional to the vapor flow rate, which starts a lean oil pump and controls the amount of lean oil pumped to the column. Cooled lean oil absorbs hydrocarbon vapors in the packed absorber column. In one type of unit the enriched gasoline (used lean oil) is returned directly to a gasoline storage

tank. Another lean oil absorption unit uses heat and reduced pressure to regenerate and re-use the lean oil, returning the recovered gasoline to storage. Cleaned air/vapor mixture is exhausted from the lean oil absorption control unit to atmosphere.

Lean oil for one type of unit is produced independently by heating gasoline in order to evaporate off the light ends. This lean oil is then cooled and stored in an insulated tank. Figure 94 shows a simplified schematic diagram of this type of lean oil absorption system.

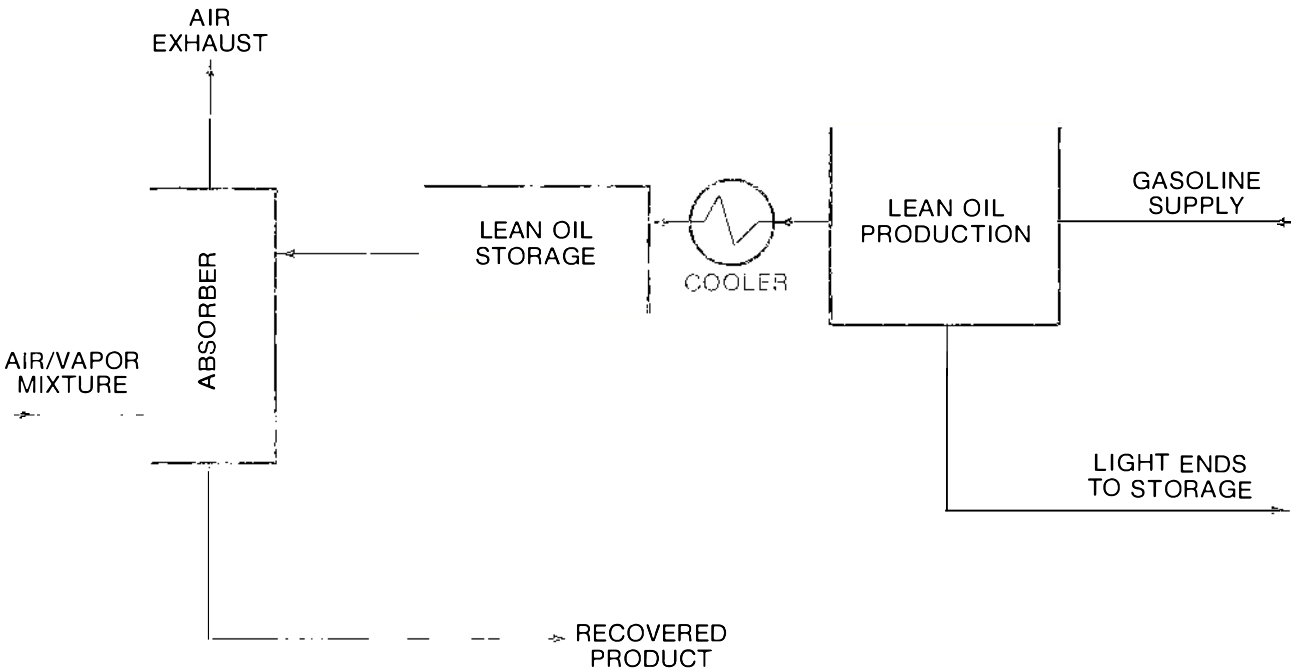


Figure 94. Schematic Diagram of a Lean Oil Absorption System.

SOURCE: Environmental Protection Agency, *Background Information Document for the New Source Performance Standards*, December 1980.

The lean oil absorption unit is not in widespread use at terminals, and oil companies have indicated a tendency toward replacing these units with other types of control systems. Generally, unsatisfactory performance has been given as the reason for the change. However, newer designs have recently been marketed and may prove to be satisfactory.

B. Tanker and Barge Emissions

Hydrocarbon emissions are generated at marine terminals when petroleum liquids are either loaded onto or unloaded from ships and barges. Loading emissions result from the displacement to the atmosphere of hydrocarbon vapors by the crude oil or refined product being loaded into the vessel tanks. Ballasting emissions are the hydrocarbon vapors displaced during ballasting operations at the unloading dock following the delivery of the cargo.

Two distinct sources contribute to the total loading emissions. The emissions during the early stages of loading are composed primarily of vapor present in the tank prior to loading, originating from evaporation of the previous cargo. This is called the arrival component. In addition, hydrocarbon vapor is formed by evaporation of the cargo being loaded. This is called the generated component.

Ballasting emissions occur when an empty tanker or ocean barge takes on ballast water before leaving port, to maintain trim and stability on the subsequent voyage. (Inland waterway barges do not take on ballast water.) These ballasting emissions consist of the vapor present in the ullage space of a compartment at the start of unloading together with the additional vapors that are created when the air drawn into the emptying tank absorbs hydrocarbons evaporating from the liquid surface. (Ullage is space between the cargo surface and the underside of the deck.) The hydrocarbon concentration of the vapor in the ullage space before unloading is directly related to the ullage prior to discharge and to the volatility of the cargo to be discharged. The vapor generated during and after unloading depends chiefly on the volatility.

Hydrocarbon vapors can also be created by crude oil washing of cargo tanks during unloading. As the cargo tank is emptied, inert gas is introduced. The inert gas and hydrocarbon vapors will be subsequently released to the atmosphere if they are not controlled during ballasting. Emissions associated with crude oil washing and subsequent ballasting have not been studied sufficiently to be quantified.

A 1981 American Petroleum Institute (API) document, "Atmospheric Emissions from Marine Vessel Transfer Operations," presents correlations and factors to estimate the total hydrocarbon vapor emissions resulting from three different marine vessel operations: the loading of gasoline into tankers and barges; the loading of crude oil into tankers; and the ballasting of crude oil tankers. The procedures are not applicable for estimating loading or ballasting emissions from VLCCs or from vessels that employ crude oil washing, and the bulletin does not address crude oil loading into barges, gasoline tanker ballasting, or in-transit losses. Typical overall factors and equations for calculating emissions are contained in the API document.

Regulatory agencies have periodically proposed measures for reducing marine vessel emissions in port, including the use of vapor processing equipment and the application of alternative loading methods. To date, neither specific hardware nor procedures have been developed, and their feasibility remains questionable.

Vapor recovery would capture the hydrocarbon vapors displaced during loading and during dock-side ballasting to convert the vapors into petroleum liquid by means of refrigeration, absorption, adsorption, and/or compression, or dispose of the vapors by incineration. (These systems are described in the discussion on tank truck emission control in this chapter.) For marine operations, however, this control approach has several disadvantages: cost, added safety risk, vessel retrofit problems, and reduced dock

space. EPA has initiated a demonstration study to further investigate these factors during gasoline loading of inland waterway barges.

Several operational control techniques have been considered as alternatives to the use of vapor control systems. These approaches include segregated ballasting, tank cleaning, slow loading, short loading, and the routing of vapors into tanks that are being emptied. These methods are, of course, in addition to the widely practiced technique of bottom loading.

Segregated ballasting became a requirement, except where crude oil washing is authorized, as of June 1981 for new tankers using U.S. ports, with later effective dates for retrofitting existing tankers. This regulation eliminates ballasting emissions from tankers and ocean barges but reduces the cargo capacity of the vessel by approximately 30 percent.

Tank cleaning, if practical, would reduce only slightly the arrival component of the loading emissions. Slow loading would appear to be an effective technique, but investigations to date have not shown that any appreciable emission reductions would be realized by slowing the typical existing loading rates. The short loading approach is considered to be impractical from both operational and cost standpoints and may actually increase emissions.

1. Regulatory Considerations

The Clean Air Act does not address the regulation of air emissions from marine vessels. As a result, this issue is being addressed by states and localities. If non-uniform requirements result, they could impose a burden on interstate and foreign maritime commerce.

Marine transportation is interstate and foreign in scope, involving both U.S. and foreign flag vessels. In recognition of the international nature of merchant shipping, the maritime nations of the world have vigorously opposed the unilateral regulation of vessels. Congress has acknowledged this concern and has generally structured laws in accordance with international agreements. Consistent with this policy of international cooperation, Congress in general has also attempted to assure regulatory uniformity in maritime matters within the United States. As a consequence, state and local actions with respect to vessels have been largely precluded due to overriding federal jurisdiction. However, vessel atmospheric emissions have not been clearly addressed by Congress.

The Clean Air Act and its amendments recognize the differences between stationary and mobile source emissions and specifically account for these differences in the case of aircraft. Title II of the Act gives jurisdiction to the federal government in the regulating of aircraft and specifically prohibits states or local authorities from developing regulations inconsistent with those developed at the federal level. Marine vessels, however, which are clearly a mobile source and similar to aircraft in the interstate

and foreign nature of their trade, are not specifically addressed in Title II. This exclusion of marine vessels has created uncertainty among the states, local authorities, and the federal EPA as to who has the authority to control vessel stack and vent emissions.

This uncertainty over authority has recently led to numerous and conflicting vessel emission regulatory proposals issued by various states and local authorities. Should this uncertainty continue, disruptive regulatory mechanisms will be created and serious restrictions would be imposed on maritime commerce.

Further, the feasibility of safely complying with regulations developed unilaterally by state and local authorities is a major concern. Safe transportation of cargo, including crude oil or petroleum products, can be ensured only by rigid adherence to carefully developed design and equipment specifications and operating procedures. This in turn requires a cooperative effort among all segments of the maritime industry, the Intergovernmental Maritime Consultative Organization (IMCO), a branch of the United Nations, and the U.S. Coast Guard, which is responsible for safe operation of vessels in U.S. waters. This cooperative effort is essential to ensure that vessel equipment and operating procedures are compatible on a national and international basis.

The respective responsibilities of the states, local authorities, EPA, and the Coast Guard with regard to marine vessel air emissions should be clarified. The following jurisdictional issues need to be addressed.

- Pre-emption of state and local regulations governing marine vessel air emissions
- Consistency with international marine vessel air emission standards
- Coordination with the Coast Guard on operational practices and equipment required to comply with federal regulations for marine emission control.

In addition, the need to control marine emissions and the safe application of these controls must be demonstrated prior to the development of regulations. Studies should be conducted to determine the extent to which vessel emissions affect air quality and the cost effectiveness of safely controlling vessel emissions relative to controlling similar emissions from other sources. These studies must address the technological feasibility of safely controlling emissions, specifically the unresolved safety issues that exist in the application of hydrocarbon vapor control technology to marine operations.

V. Marketing Emissions

For the purposes of this report, the marketing segment of the petroleum industry is defined as those operations involving the

delivery of refined products from terminals and bulk plants to service stations and consumer accounts such as businesses and farms, and the dispensing of gasoline to motor vehicles. Loading of tank trucks at the two supply points was covered in the preceding section on transportation. Products other than gasoline are not addressed because they have a low vapor pressure, are a low-volume product, or are not handled by this segment of the industry.

During the marketing operations, hydrocarbon emissions can occur from the tank truck in transit to and from the service station,[28] the underground tank as it is filled with gasoline from the truck, the underground tank during the time between fillings, and the automobile tanks during refueling. Each of these sources is discussed below, as are their control techniques. The emission factors, except for in-transit losses, are summarized in Table 55.

A. Tank Truck In-Transit Losses

Emissions from the tank trucks can occur from the hatches and pressure/vacuum vents on the truck compartments as the truck is in route between the terminal or bulk plant and the service station.

TABLE 55

Hydrocarbon Emissions from Gasoline Service Station Operations

Emission Source	Emission Rate: Pounds Per Thousand Gallons Throughput	Emission Rate: Kilograms Per Thousand Liters Throughput
Filling Underground Tank		
Submerged Filling	7.3	0.88
Splash Filling	11.5	1.38
Balanced Submerged Filling	0.3	0.04
Underground Tank Breathing	1	0.12
Vehicle Refueling Operations		
Displacement Losses (Uncontrolled)	9	1.08
Displacement Losses (Controlled)	0.9	0.11
Spillage	0.7	0.084

SOURCE: Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Supplement 7, April 1977.

Such losses are considered to be insignificant because regulations prohibit travel with the hatch covers open and there is a more recent requirement that the trucks undergo a pressure/vacuum test for leaks at least once a year. These regulations will come into effect in all areas that require vapor control during loading at the terminal and during delivery at the service station.

B. Underground Tank Losses

For delivery of gasoline to the service station, the tank truck compartments are connected to the underground tanks by a hose that makes a liquid-tight connection with the fillpipe of the tank. Valves on the truck are opened to allow the gasoline to flow by gravity into the tanks from the compartments. Emissions occur when the hydrocarbon vapors in the storage tank are displaced through the tank vent by the incoming gasoline.

As with truck loading, the quantity of the emissions primarily depends upon whether the fillpipe extends to within a few inches of the bottom of the tank to ensure submerged filling or whether it extends only to the top of the tank or slightly further, thereby causing splash filling to occur. Submerged filling is required in many ozone nonattainment areas and has been the standard practice of the industry for many years. An average hydrocarbon emission rate for submerged filling is 7.3 pounds per 1,000 gallons of transferred gasoline, and the rate for splash filling is 11.5 pounds per 1,000 gallons (see Table 55).[29]

Emissions from underground tank filling operations at service stations can be further reduced by the use of the vapor balance system (Figure 95). This system employs a vapor return hose, which returns gasoline vapors displaced from the underground tank to the tank truck compartment being emptied. The control efficiency of the balance system ranges from 93 to more than 99 percent. Hydrocarbon emissions from underground tank filling operations at a service station employing both the vapor balance system and submerged filling are not expected to exceed 0.3 pound per 1,000 gallons of transferred gasoline.[30]

Another underground tank emission source is breathing loss, which is relatively insignificant. This loss is created by changes in product temperature or barometric pressure. The temperature of the product in the underground tank is influenced primarily by the temperature of the gasoline being delivered, not by ambient air temperature changes.

C. Vehicle Refueling Losses

An additional source of hydrocarbon emissions at service stations is the vehicle refueling operation and the associated spillage. The refueling emissions are attributable to vapors displaced from the automobile tank by the dispensed gasoline and to spillage. The quantity of displaced vapors is dependent upon gasoline temperature, auto tank temperature, gasoline vapor pressure, and dispensing rates. Although several correlations have been

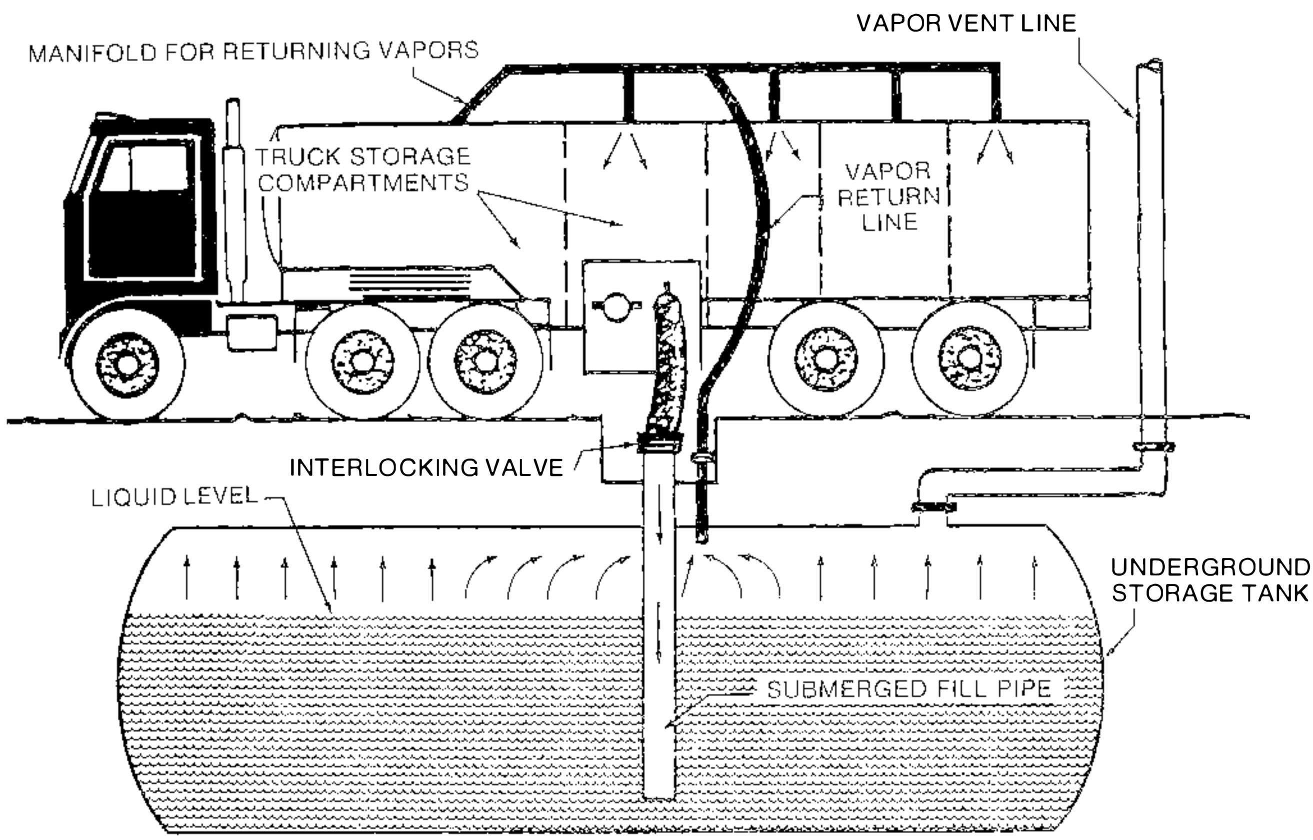


Figure 95. Vapor Balancing During Gasoline Delivery to Service Station.

SOURCE: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Supplement 7, April 1977.

developed to estimate losses due to displaced vapors, significant controversy exists concerning these correlations. It is estimated by EPA that the hydrocarbon emissions due to vapors displaced during vehicle refueling average 9 pounds per 1,000 gallons of dispensed gasoline.[31]

The quantity of spillage loss is a function of the type of service station (self service or full service), vehicle tank configuration, and operator technique. An overall average spillage loss is 0.7 pound per 1,000 gallons of dispensed gasoline.[32]

Two types of vapor control systems have been developed to reduce refueling emissions; one is the balance system and the other is the assist system. Both systems use special nozzles, hoses, and piping to convey the vapors displaced from the vehicle fuel tank to the underground storage tank vapor space. The most commonly used system is the balance system, which depends primarily upon the pressure created in the vehicle fuel tank by the incoming liquid to force the vapors through the return line to the underground storage tank. The vapor recovery nozzle is equipped with a spring-loaded bellows that is compressed when its faceplate is pushed against the lip of the vehicle fillpipe. A catch on the nozzle latches with the turned-in lip of the vehicle fillpipe. The latching action

opens the return passageway, which conducts gasoline vapor displaced from the vehicle tank to the vapor return hose, through the underground piping, and back to the underground tank. Ideally, a seal is created between the nozzle and vehicle fillpipe, and the nozzle vapor return passageway is opened to the vapor return hose only. A balance system is depicted in Figure 96.

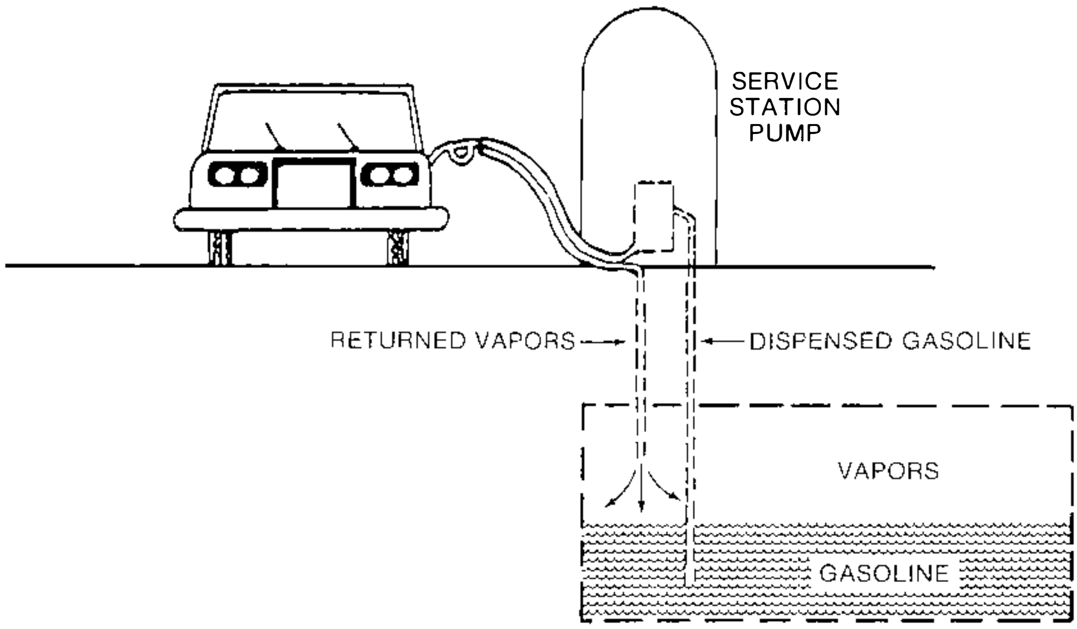


Figure 96. A Balance-Type Automobile Refueling Vapor-Recovery System.

SOURCE: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Supplement 7, April 1977.

The other type of service station vapor control system is the assist system. This system is similar to a balance system but relies on a vacuum-inducing device such as an aspirator, a pump, or a blower to assist in moving the gasoline vapors from the vehicle tank to the storage tank. The assist nozzle is equipped with a spring-loaded bellows, which, although similar to that on the balance nozzle, is more easily compressed when the nozzle is inserted into the vehicle fillpipe. The vacuum device creates a vacuum, which directs the gasoline vapors to the underground tank. Some vacuum systems also draw a small amount of air into the nozzle, so that more vapor is returned to the underground tank than the volume of gasoline withdrawn. A processing unit, which incinerates these excess vapors, is sometimes used on the assist system.[33]

Results of tests conducted by the California Air Resources Board show that both the balance system and the assist system are more than 95 percent effective in reducing refueling emissions. The overall performance of both systems will improve somewhat because of the standardized fillpipe configuration that was established by the Society of Automotive Engineers for the 1978 model-year vehicles. As more of the vehicles on the road have this

configuration, it may be possible to further standardize the nozzle design to facilitate obtaining a vapor-tight connection between the vehicle and the system.

Two other approaches to control vehicle refueling emissions have been considered periodically for a number of years, but neither has been accepted unanimously by the petroleum industry, the automotive industry, and the regulatory agencies. One approach is to retain the displaced vapors on the automobile by adsorbing them on activated carbon, which would be subsequently regenerated in place and the vapors routed to the engine for combustion. This technique was evaluated with positive results by API in the late 1970's, but EPA did not accept it as a viable alternative, perhaps because it would have been another environmental requirement for the automotive industry to meet.[34]

The other alternative is to eliminate the automobile's fuel tank vapor space by use of a flexible diaphragm or a collapsible bladder in the tank. These techniques were studied by the automotive industry in parallel with the API's investigations but were judged not to be practical.

Controls for vehicle refueling emissions are currently required only in specified areas of California by local regulations and in Washington, D.C. EPA has not issued federal guidelines or regulations on refueling and the controls are not voluntarily installed by the industry because they are less cost-effective than controls on other hydrocarbon emission sources.

Before vehicle refueling controls are proposed on either a national basis (or on a local basis), four major concerns must be considered.

- The controls (either stationary or onboard) may produce only a minimal improvement in air quality. According to EPA, controls at service stations are intended to recover a maximum of only 2 percent of the hydrocarbons emitted in a typical region[35] Further, EPA cannot demonstrate that these controls will have any measureable impact on air quality; i.e., in areas where stationary control equipment currently is required, hydrocarbon emissions are decreasing; but ozone levels are not showing a corresponding decline.

- The controls may not be effective without a costly and stringent inspection and maintenance program. Air quality benefits may not be realized due to enforcement problems. EPA lacks data on enforcement problems from the District of Columbia and California and on the potential cost to EPA or to the state and local governments if a strict inspection program is required.

  Costs are large compared to anticipated benefits.[36] Achievement of this minimal improvement in air quality would require imposition of large cost burdens on either gasoline retailers or automobile manufacturers.

According to industry data, independent gasoline retailers would be faced with equipment installation costs of up to $1,750 per nozzle and an additional $260 per year in maintenance costs if stationary vapor recovery systems were to be mandated by EPA.

Information presented by the motor vehicle manufacturers indicates that on-board equipment could add between $16 and $20 to the cost of a new automobile. Total annual cost to the industry would be based upon an estimated 10 million new car sales per year.

- Most states are expected to meet the existing ozone standard prior to 1987 without Stage II vapor recovery. Gasoline refueling vapors are very small on a tons-per-day basis in the context of the hydrocarbons emitted into the atmosphere. Controls on other hydrocarbon sources are currently being implemented and will be in place before refueling controls are necessary.

These four points were recognized by the U.S. Senate Committee on Appropriations and addressed in its 1981 report.[37]

EPA's photochemical oxidant standard, which could impact the installation of Stage II controls, was challenged in the U.S. Court of Appeals (D.C. Circuit). The recent court decision rejected arguments that the ozone standards are too stringent.[38] The petitioners challenged the primary and secondary NAAQS for ozone as set at 0.12 parts per million (ppm) by EPA under the Clean Air Act in regulations published on February 8, 1979. API, the city of Houston, and the Commonwealth of Virginia contended that the Administrator of EPA erred by establishing standards that were too strict. The Natural Resources Defense Council contended that the Administrator established standards that were too lenient. Procedural challenges were also raised. The court upheld the ozone standards as set. It said they were proper under the Act, and that such procedural errors as did occur do not require invalidation of the final standards. API has appealed the decision to the Supreme Court.

WATER AND LAND

Industry practices and environmental regulations control the discharges of raw materials or products to surface waters or to land (where they can contaminate groundwaters). This control is accomplished through both the treatment of contaminated wastewater before discharge and an intensive system of spill prevention. In addition, as spills cannot always be prevented, procedures are in place to detect and clean up spills when they occur.

The distribution of petroleum raw materials and products is conducted in a predominately closed system, which minimizes losses. Even with the best prevention measures, however, spills and leaks still occur. Where they do, petroleum products can be discharged

to surface water or the land. Large surface water spills can create unsightly incidents. The management and cleanup of these spills is discussed in Chapter Six. Spills to land are generally more localized, but they can cause fire and explosion hazards and can contaminate groundwater Once underground, the spilled petroleum is difficult to clean up.

This section of the report presents information on wastewater generated and discharged as a result of routine operations as well as releases that unavoidably occur as a result of spills or leaks.

I. Applicable Laws and Regulations

The primary law that empowers EPA to write regulations controlling discharges and spills to surface waters is the Clean Water Act. Regulations promulgated under the authority of the Clean Water Act impact storage, transportation, and marketing facilities through programs that include the National Pollutant Discharge Elimination System (NPDES) permit system, the Spill Prevention, Control and Countermeasures (SPCC) program, and controls on the discharges of oil and hazardous substances.

In addition to federal laws, essentially all the states have a framework of regulations for groundwater protection. Some of the states, including California, Alaska, and Wyoming, have extensive regulations that address all aspects of groundwater protection Seven other states are considered by an EPA study to have regulations that address essentially all aspects of groundwater protection.[39] The remainder of the states address the protection of groundwater resources with regulations that reflect their assessment of their states' potential problems.

On a local basis, particularly in urban regions, fire departments play a major role in the management of spills and leaks that have the potential to, or do, endanger the community. Fire departments have a well organized set of procedures and codes to respond to problems potentially harmful to citizens and property

Marine transportation, vessel design, and vessel equipment are regulated under the Port and Tanker Safety Act. Many pipeline activities are regulated by DOT regulations.

II. Impact of Discharges on the Environment

Discharges to surface waters from storage, transportation, and marketing facilities result primarily from storm water runoff, process wastewater, and spills. Both contaminated storm water runoff

and process wastewater are treated for oil and grease (O&G) removal before discharge. As a result, they produce little in the way of environmental impact. In addition, uncontaminated, untreated storm water runoff from facilities has little impact. Spills, however, can cause highly visible and unsightly messes, but to date effects have been determined to be reversible and generally not long term. Spills and their fate and effects are discussed in more detail in Chapter Six.

Spills, by definition, involve the loss to the environment of a discrete amount of product. Typically, the escaped product is confined to a localized area, as much product is recovered as possible, and the spill site then reclaimed.

Leaks, on the other hand, are potentially more subtle and serious problems. They may not be detected promptly until extensive areas are contaminated with large quantitites of product. Large-scale terminals and transportation facilities are usually located in reasonably isolated sites, thus the potential for endangerment to people and property from leaks is minimized; the principle concern is the potential for groundwater contamination.

III. Spill Incidents

Section 311 of the Clean Water Act as amended in 1978 specifically addresses oil spills. The Act prohibits the discharge of oil in quantities that "may be harmful." Spills into or upon navigable waters of the United States, adjoining shorelines, or territorial seas must be reported and civil penalties are assessed accordingly. Failure to report a spill can subject a discharger to criminal penalties.

Reports of spills are made to the National Response Center, which is manned by the U.S. Coast Guard. The Coast Guard annually prepares a report presenting an analysis of spill incidents. Oil spill information for the 1981 Coast Guard report, Polluting Incidents In and Around U.S. Waters, for sources in the storage, transportation, and marketing sector of the industry is summarized in Table 56. The methods used to prevent and control these spills, both onshore and offshore, are discussed in detail in the following sections. The impact of these spills is discussed in detail in Chapter Six.

IV. Offshore Pollution Control and Prevention

A. Storage and Pipelines

Offshore storage and pipeline facilities and pollution control aspects are discussed extensively in the Industry Operations section of this chapter. There are few routine wastewater discharges associated with offshore storage and pipelines. Discharges are primarily associated with accidental spills.

Major loss of stored oil or damage to the storage facility is possible from hurricanes, collision by seagoing vessels, blowouts

TABLE 56

Reported Oil Spill Incidents for Sources in Storage, Transportation, and Marketing -- 1979-1980*

	1979			1980		
	Number of Spills	Volume (Gallons)	Percentage of Total Volume	Number Of Spills	Volume (Gallons)	Percentage of Total Volume
Total Reported, All Sources	10,990	10,500,344	100	7,837	7,332,699	100
Tank Ships	706	2,561,925	24	499	1,471,096	20
Tank Barges	930	1,200,680	11	751	1,596,079	22
Railway Vehicles	47	122,760	1	31	66,485	1
Highway Vehicles	346	352,480	3	156	102,161	1
Bulk Storage	225	334,338	3	223	362,005	5
Pipelines	594	3,301,470	31	475	1,719,420	23
Marine Facilities	620	552,818	5	519	795,836	11
Land Facilities	199	268,278	3	110	60,773	1
Total for Storage, Transportation, and Marketing Sources	3,667	8,694,749	83	2,764	6,173,855	84

*Source of data: Department of Transportation, U.S. Coast Guard, Polluting Incidents In and Around U.S. Waters, Calendar Years 1979 and 1980. Totals may not add due to rounding.

on adjacent wells, and fire. Failure of the facility may also result from undermining of the structure foundation by wave motion.

Experience has shown that almost any fluid spilled on a platform is a potential source of pollution. For this reason, platform decks are equipped with gutters and drains to direct the spills to a central gathering tank where the spill material may be treated or, if it is not suitable for treating, directed to shore for disposition without danger of pollution. Since a substantial part of spilled material contains flammable hydrocarbon material, it is advisable that adequate safety measures for prevention of fire and explosion be incorporated in the collection tank at the time of design and installation. Entrained gas, which is likely to be associated with any live oil spills that might be directed to the collection tank, should be provided for by connection of the collection tank to the offshore structure's gas flare or vent line system.

Offshore structures in different parts of the United States may require considerably different designs to conform with environmental conditions encountered. In recognition of this, the various

Consideration must be given for the security of offshore storage facilities against water action, wind action, and collision. In all offshore structures, the basic engineering considerations are rational design for the forces to be encountered and the loads to be borne, realistic appraisal and forecast of the forces to be suffered, and engineering study of the site on which the structure is to be built. Maritime regulations and strengthened coordination between petroleum and other maritime activities will minimize

Important to the prevention of fire and pollution are good communications; highly instrumented facilities; inhibition of corrosion; frequent inspection; early detection of leak sources; warning systems for major storms and ocean shipping; and highly trained, responsible operating personnel.

B. Tankers and Barges

During the 1970's, significant progress was achieved by the combined efforts of governments and the marine industry, domestically as well as internationally, to prevent and control oil pollution of the seas. The goal of the 1980's should be to maintain this momentum through increased efforts to comply with existing regulations and procedures rather than by the promulgation of new regulations or enactment of new legislation.

For many years, the petroleum industry has taken positive steps to increase safety and minimize accidents in order to avoid oil spills, but recognizes that oil on the ocean and coastal waters remains a major problem -- one that is international in scope and requires the active participation of the entire petroleum industry for solution. The problem encompasses all classes of ships as well as other operations, many of which are outside the petroleum industry's control. While tankers present the potential for large-scale accidental spills, studies indicate that nontankers are actually contributing to sea pollution to a greater extent than tankers through routine operational discharge.

1. Vessel Design

A major change in vessel design and equipment was brought about by the enactment of the Port and Tanker Safety Act of 1978. The United States unilaterally passed this legislation in advance of the correspond ng international protocol, Tanker Safety and Pollution Prevention of 1978. The Port and Tanker Safety Act sets minimum standards for new and existing crude oil tankers and product carriers. The Act requires segregated ballast tanks, dedicated clean ballast tanks, or crude oil washing equipment to be provided for existing tankers larger than 40,000 DWT entering U.S. ports by June 1, 1981. Later deadlines are set for retrofitting smaller tankers and product ships. These new requirements contribute

significantly to oil pollution abatement from routine tanker operations.

2. Licensing

A 1978 International Convention on Standards of Training, Certification and Watchkeeping for Seafarers (STCW) will shortly become effective. It provides for the submission of national licensing programs and for improvements in training, qualification, and certification of tanker personnel. The United States, by the enactment of the Ports and Tanker Safety Act of 1978, has mandated the requirements contained in the STCW, with an effective date of June 1, 1978, for all vessels entering U.S. waters. The unilateral imposition of the earlier date by the United States, especially in view of the extensive administrative requirements both on foreign flag states and training facilities, will create unnecessary problems on the world shipping community.

3. Vessel Discharges and Spills

Oil on the ocean and coastal waters remains a major problem -- one that is international in scope and encompasses operation of all classes of ships, as well as other operations, many of which are outside the U.S. petroleum industry's control. While tankers present the potential for large-scale spills, studies indicate that nontankers in their daily operations are actually contributing to sea pollution to a greater extent than tankers through routine operational discharges, which are frequently within the law.

In one sense, the United States is more likely than many countries to be exposed to pollution by oil because of the great length of its coastline (12,383 miles), although traffic density in any particular location is also a factor. In addition to these extensive coastal waters, there are some 25,000 miles of navigable inland waterways in the United States.

The practices of the U.S. petroleum industry are an offsetting factor. For many years the petroleum industry has taken positive steps to increase safety and minimize accidents in order to avoid oil spills.

a. Pollution Sources

Oil pollution from vessels can occur through vessel discharges, including pumping of oily bilges and disposal of oil tank washings or ballast from tankers, and through those mishaps, such as accident, collision, and vessel grounding, that result in the release of oil.

(i) Vessel Discharges

One of the principal causes of oil pollution is the discharge of dirty ballast and tank washing by oceangoing tankers, most of which are engaged in international trade. The second principal source of oil pollution is the pumping of bilges overboard from

thousands of vessels, big and small. Oceangoing vessels are restricted by international convention and the federal Clean Water Act from the practice of discharging oily water and slops until at least 50 miles from land and then only in accordance with strict discharge criteria. Passenger vessels and some types of dry cargo vessels find it necessary, as fuel oil is consumed, to replace it with water ballast in order to maintain proper stability. In some cases, this practice requires filling bunker tanks with seawater ballast, resulting in contaminated water, which must be disposed of in accordance with international agreements and national regulations. In inland waters, tugs, barges, ferries, and the multitude of diverse marine craft that ply our rivers, lakes, bays, and sounds are prohibited from discharging any oil residues into our navigable waterways.

While oil pollution is a cause for serious concern, the discharge of raw sewage and food waste from vessels that daily ply our waters is also significant. Through international agreement, most seagoing vessels today are provided with sanitation devices for sewage treatment prior to overboard discharge. The requirement for sewage treatment applies to all classes of vessels.

(ii) Mishaps -- Collisions and Groundings

The human element covers a wide range of factors that contribute to spills as well as other mishaps; for example, inattention to duty leading to a minor tank overflow, or misjudgment in navigation resulting in grounding, collision, fire, possible explosion, or a major pollution incident. Material/equipment failure such as steering gear or loss of main propulsion plant has had disastrous effects and, in some instances, has resulted in complete loss of cargo and vessel, with occasional loss of life.

A prominent cause of oil pollution is the collision and/or grounding of tankers or barges engaged in bulk transportation of oil. This type of pollution from vessels, because it often receives wide publicity, is the best known to the public. Of course, large spills of the type from the Amoco Cadiz are a major problem.

The great majority of collisions and groundings occur in confined waters. Poor visibility, traffic congestion, and lack of communications are contributing factors. The problem is not, of course, limited to oil tankers. All ships, large and small, commercial and noncommercial, private and government-owned, are faced with the problem. Neither is the problem solely an American problem. On the contrary, it is a matter of general international concern and responsibility. U.S. Coast Guard statistics indicate that human error is the greatest single contributing factor in collisions and/or the grounding of vessels.

b. Prevention and Control

More detailed descriptions of methods of prevention and control of oil spills are given in the sections that follow. Generally

speaking, however, research and development sponsored by the petroleum industry is continually directed toward prevention of oil spills by improving equipment reliability and pollution-control techniques, even beyond the standards of national statutes or international law. From industry efforts have come load-on-top (LOT) techniques for tankers, the practice of crude oil washing as a method of cleaning tanks, development of on-board oil/water separators, improved loading and unloading procedures, and the building of more and larger shore ballast-handling facilities in order to further reduce discharges at sea.

Research projects have produced improved navigation systems and steering devices that have increased the maneuverability of ships. Ship designers are investigating a variety of new features to minimize the seriousness of accidents. In addition, individual companies are increasingly emphasizing the training of ship personnel, both at industry schools and aboard ship, to improve navigation and general operating techniques.

Internationally, the industry has strongly supported the efforts of IMCO in improving international standards of vessel design and operation to prevent pollution, and in developing international agreements prohibiting discharges of oil at sea. Even though international law allows some oil discharge 50 miles or more from shore, depending upon locale, oil companies are now attempting to achieve a practicable, strict policy against discharge of oil or oily ballast anywhere in the world's oceans.

While the petroleum industry is working hard on all aspects of prevention of oil spills, it also recognizes that with over 3,200 tankers and a multitude of other large ships plying the world's oceans, some accidents still take place. The petroleum industry has therefore taken steps to be sure that means are available to handle the costs of cleanup of oil spills and to reimburse persons sustaining pollution damage. The petroleum industry has developed voluntary compensation plans such as TOVALOP and CRISTAL for this purpose (described later in this chapter). At the present time, two conventions, the 1969 Civil Liability Convention and the 1971 International Fund Convention, are yet to be ratified by the United States.

Barge movements on inland waterways as well as in coastal waters represent an important part of the nation's petroleum traffic. Several types of technical, procedural, and training projects applicable to tankers are also generally applicable to barges and their movements. The industry actively supports increased attention to local cooperatives to clean up oil spills and increased coordination with concerned local and federal groups.

Pollution of the environment by all ships on the waters is a matter that concerns all of society; industry, government, and the general public all bear the costs. Furthermore, all have a direct or indirect responsibility for such relevant factors as human performance; the installation, operation, and use of navigational aids; and the creation of and compliance with appropriate law and

regulation. This interrelationship of responsibility is apparent from the examination of the attention given to specific operations.

(i) Control of Tank Washings and Oily Ballast

To combat oil pollution from disposal of oily tank washings or ballast, the industry instituted the LOT procedure in the 1960's. This procedure may be described as retaining on board ship the oil/water mixtures resulting from tanker compartment cleaning or from the use of compartments to carry ballast so that they will commingle with compatible new cargo loaded "on top." The general practice of LOT has significantly reduced the overboard discharge of tank washings and oily ballast.

A new method developed to improve LOT is a combination of several slop tanks used as a cascade system, which allows further settling and reduction of oil content of the wastewater that may be discharged overboard. The shape and configuration of the slop tank, the positioning of inlets, outlets, baffles, or weirs in the tank, and the use of heating coils and chemical flocculants help to avoid excessive turbulence and entrainment of oil with the water, thereby reducing the oil content of the decanted water discharged to the sea.

Eventually all tankers will be fitted with an oil content monitoring arrangement to check the purity of any water discharged directly to the sea from the slop tanks. Also, effective oil/water interface detectors are being considered for rapid and accurate determination of the oil/water interface.

A more recent technique to gain greater control over tank washings and oily ballast being dumped in the oceans is the industry-devised crude oil washing system. This is a cargo tank cleaning system in which crude oil is the washing medium. Crude oil is discharged through fixed tank washing machines positioned so that oil impingement on tank bulkheads and internal structure cleans off the sludge and oil residue remaining in the tank after the cargo is discharged. The spray action and subsequent run-down put the semi-solid oily residues back into liquid suspension so that they can be collected, along with the crude oil used in the washing process, and then discharged as part of the cargo. Crude oil washing is done during the cargo discharge operation.

Crude oil washing systems require that the vessel be fitted with washing machines that are fixed in place and permanently connected to the cargo pumping system. A vessel using crude oil washing must be equipped with an inert gas system to maintain the cargo tanks in an inert condition during the washing operations. The cargo discharged includes most of the tank clingage and sludge and thus reduces tank residues.

The International Conference on Tanker Safety and Pollution Prevention was convened under the auspices of IMCO in London, February 1978, in response to The President's initiative on oil pollution announced in March 1977. The basic U.S. initiatives, as put forward to IMCO, stemmed from a series of tanker accidents that

occurred in or near U.S. waters during the winter of 1976-1977, and that resulted in both loss of life and property and threat of serious pollution. The Port and Tanker Safety Act of 1978 unilaterally requires that segregated ballast, clean ballast, or crude oil washing be provided by June 1981 for existing crude oil tankers. New tankers will be required to have both segregated ballast and crude oil washing.

- Segregated ballast tank regulations require ballast tanks that are completely separated from the cargo oil and fuel systems and that are permanently allocated for the carriage of water ballast. Enough segregated ballast capacity must be provided to enable the vessel to meet specific minimum draft and maximum trim requirements in any ballast condition. The intent of this requirement is to provide vessels with enough segregated ballast capacity so that the ship may be operated safely on ballast voyages without putting water ballast in cargo oil tanks except in unusually severe weather.

- The dedicated clean ballast tank concept can be used as an option on existing product carriers and as an interim means of phasing in the segregated ballast tank/crude oil washing options on existing crude oil carriers. The clean ballast tank concept would require a vessel to clean certain tanks that would normally be used to carry cargo and dedicate these tanks solely to the carriage of clean ballast water. Only enough tanks are set aside as ballast as are necessary to meet the draft and trim requirements of the segregated ballast concept.

(ii) Control of Bilge Liquids and Other Wastes

Engine room bilges on all types of vessels, large or small, almost always contain oil, and in the past they were pumped overboard. Current regulations prohibit this practice and systems are required on board to treat the bilge water prior to discharge. Alternatively, the waste can be retained in a holding tank for discharge into a terminal receiving facility.

Although oil pollution from an overflow of a cargo or bunker tank is often attributable to carelessness, inattention to prescribed procedures, or human error, a number of innovations have been developed to minimize human error. New tankers contain a central control room from which the operator can remotely control every cargo valve on the vessel, stop and start the pumps, and, through remote instrumentation, observe the exact level of the cargo in each tank. The officer in charge is also equipped with VHF radio so as to be in constant communication both with the shoreside control tower at the loading or discharging terminal and with the men on deck. In the interest of improving communications, the ship's officers and crew are equipped with two-way radios to maintain constant contact with the central control room and each other. The combination of a central control room with instant

communication aboard the vessel and with the shoreside installation provides positive control of cargo transfer operations.

Marine equipment manufacturers continue to improve their products generally and have developed new forms of specific assistance to the petroleum industry in a number of areas, particularly in the field of electronics. Vessels are equipped with instruments that indicate loads and stresses. Closed circuit television can be used to monitor machinery. Automatic or remote control devices aid in all aspects of the vessel's operations.

Coatings to protect against corrosion have been greatly improved in recent years, with the result of both an added safeguard against steel deterioration and the simplified cleaning of tanks. Even with these precautions, oil pollution may occur from fractures in shell plating caused by heavy weather, which can be neither avoided nor its effects controlled.

The responsible elements of the petroleum industry maintain engineering staffs, inspectors, and professional shipboard personnel to carry out preventive maintenance aboard ship and to ensure that appropriate inspections and repair are accomplished in drydock. The U.S. Coast Guard enforces laws governing the safety of U.S. shipping by examining and approving all lifesaving apparatus, and by inspecting each U.S. flag vessel at specified intervals, including a special hull and machinery survey every four years. Hull and machinery insurance underwriters, along with the various classification societies, are constantly seeking ways to improve equipment and operating procedures. Although regulations and procedures for the inspection of all vessels have been in effect for a long time, the operating condition of vessels has been improved by the agreement to international standards applicable to all vessels, regardless of ownership or flag of registry. For example, international agreement has been reached as to the maximum time a vessel is allowed to remain in service between drydockings; this has improved maintenance worldwide.

Another area in which members of the oil industry, as owners and operators of tankers, have a major interest is in the design and construction of equipment. One objective is to avoid or lessen the escape of oil or other noxious products in the event of stranding or collision. Ships suffering structural damage because of severe weather or improper loading or discharging of cargo has long been a concern to ship owners, builders, and the classification societies. To overcome these problems, a number of select, very large vessels of all types have been fitted with built-in, continuous-monitoring stress recorders that measure the effects of wave action on the hull in addition to the effect of stress created by the distribution of cargo within the hull. The accumulated information received from the continuous monitoring of the stresses exerted upon the vessels has provided to naval architects and the shipbuilding industry valuable information in the design and construction of vessels capable of withstanding greater stress.

(iii) Navigation Techniques and Manpower Training

Traffic separation lanes have been established in some congested waters, both internationally and domestically, with encouraging results. Wider use of this technique is being considered. Previously, use of these lanes had been voluntary; however, mandatory use has been adopted in some areas, i.e., San Francisco, New Orleans, Dover Straits, and the Straits of Gibraltar. Today, virtually all tankers are equipped with two radars as aids to navigation. Sonar doppler equipment has become an accepted navigational tool both at sea and during berthing operations. The various shore-based surface electronic navigation devices [Long range radio navigation (LORAN), Decca, Satellite navigation, Omega] have proved invaluable aids to navigation. Bridge-to-bridge communications have also improved the safety of navigation in narrow water passages.

An important approach in reducing marine pollution from waterborne commerce is to improve the training of tanker, barge, and terminal personnel and to improve testing and certification procedures to ensure that such personnel have the necessary skills. The importance of adequately trained personnel in marine transportation systems is graphically demonstrated by accident statistics. U.S. Coast Guard studies have indicated that 85 percent of all casualties are related to human error. Higher personnel standards augment the pollution abatement effect of improved hardware since higher levels of technology will require improvement in the knowledge and capabilities of operating personnel both in the vessel's crew and at the terminal. While the degree of environmental impact mitigation attributed to training cannot be quantified, it would follow that more intensive and formalized training programs and more rigorous examination and certification procedures will result in a major reduction of pollution incidents.

Both industry and the federal government have cooperated in training programs to upgrade personnel competence. The U.S. Coast Guard, Maritime Administration (MARAD), and EPA all have current educational and training programs related to marine pollution abatement. Formal training programs for merchant marine personnel are offered in a variety of facilities, both public and private. The major installations are the U.S. Merchant Marine Academy, operated by MARAD, six state maritime academies and colleges, the three regional training centers operated by MARAD, and the several industry training centers operated under the joint trusteeship of particular maritime unions and steamship company groups. All of these installations are in close contact with the U.S. Coast Guard and MARAD, with particular concern for updating curriculum content in keeping with the need for new skills and knowledge, whether required by regulation or not.

The U.S. Merchant Marine Academy, operated as a fully accredited college by MARAD for the education and training of new engineering and deck officers, offers an environmental pollution

control course consisting of two 10-week sessions. The Maritime Institute of Graduate Studies located at Lithicum, Maryland, offers a refresher training course to merchant marine officers including simulated radar exercises, cargo handling, and engine room control from a centralized control panel.

Shiphandling simulators, a key component of training programs, are located at the U.S. Merchant Marine Academy, Kings Point, New York (sponsored by MARAD), and at Marine Safety International, Inc., in New York (an industry school). The shiphandling simulators are a mockup of a life-size ship's bridge surrounded by a projection screen. Projected on the screen are images of a ship entering specific ports or harbors en route to a particular terminal site. The operating characteristics of the vessel are reproduced in the simulator. Control changes made by the ship's officers on the mockup bridge will produce changes in the projected image on the screen. The simulator is programmed to vary weather conditions, time of day, depth of water, peculiarities of channels, and traffic patterns.

MARAD's National Maritime Research Center at the U.S. Merchant Marine Academy has cooperated with the U.S. Coast Guard in a major revision of the _Tankerman Manual_, a U.S. Coast Guard publication specifically designed to cover the field of knowledge for the special skills required on board tank vessels.[40] The basic requirements for these skills are specified in Rules and Regulations for Licensing and Certification of Merchant Marine Personnel. The _Tankerman Manual_ covers new technologies, new operational procedures, and pollution control, in keeping with the intent of the laws and regulations. The manual constitutes a basic reference work in the field, has direct use as a course text in formal training programs for seafarers endeavoring to acquire a "Tankerman" rating, and is the source for development of examination questions for issues of the rating document.

With specific reference to the environmental protection course designed for seafarers and terminal personnel, MARAD issued in October 1975 its Curriculum on Marine Pollution Abatement and has prepared a pollution abatement manual, which is available to all existing maritime training facilities.

In MARAD's regional offices, ongoing short courses are offered to active merchant mariners in collision avoidance radar, LORAN, firefighting, and damage control. Since 1971, the U.S. Coast Guard has required that all licensed deck officers satisfactorily demonstrate their capabilities as qualified radar observers.

C. Marine Disposal Facilities

Where adequate facilities for disposal of oily wastes are not available, they must be provided at terminals, shipyards, and marine facilities. A shipmaster must dispose of the ship's waste in order to maintain his vessel in a condition necessitated by the

nature of the trade. Therefore, the greatest single step toward curbing this cause of oil pollution would be to provide sufficient facilities at terminals, shipyards, and other marine facilities to handle disposal of both oil slop and collected residue (such as waxes and rust).

Most shipyards have been slow to provide adequate tank-cleaning and slop-disposal facilities. Fortunately, there is a growth of new service companies dedicated to the collection of residues from vessels and shipyards. This activity is a result of the ever increasing value of petroleum, which more than compensates for the cost of collection. The escalating price of oil is a significant factor contributing to the reduction of this pollution source. Methods to ensure proper handling of all oily wastes should be established for all ships, regardless of ownership or registry. Without adherence to such methods and the availability of adequate disposal facilities, improper disposal will continue to cause pollution.

Many refinery marine terminals have ballast and tank-washing reception facilities. These facilities typically include a holding tank and appropriate piping to route the received water to wastewater treatment facilities before discharge. The ballast tank provides surge capacity to allow the terminal to quickly receive a large quantity of water and discharge it to a treatment system at a controlled rate. Ballast tanks are also typically equipped to skim oil from the water surface inside the tank. These facilities are described in more detail in Chapter Three

D. Oil Spill Compensation

The petroleum industry also recognizes that, even with the implementation of a wide range of accident-prevention programs, it is unrealistic to assume that tanker mishaps will never happen. It is therefore increasingly important to be certain that those responsible for a spill contain it and clean it up quickly. Prompt compensation for those who sustain damage is equally important.

Before the *Torrey Canyon* incident in 1967, no adequate national or international legal regimes existed to compensate victims of oil pollution damage or enable governments to recover costs incurred in cleaning up oil spills. As a result of international concern, industry intitiated two voluntary plans (TOVALOP and CRISTAL) to compensate for losses and damages. Additionally, two international plans were initiated by IMCO -- the Civil Liability Convention (CLC) and the Fund Convention.

1. TOVALOP

TOVALOP (Tanker Owners Voluntary Agreement Concerning Liability for Oil Pollution) is a tanker owners agreement under which each owner is obligatd either to clean up an oil spill or to pay the costs incurred by governments for doing so. Its terms encourage prompt cleanup and claims settlement. Tanker owners and bareboat

charterers who have signed this agreement carry special insurance to cover possible costs. TOVALOP became effective in 1969 and covers 99 percent of the world tanker fleet.

2. CRISTAL

CRISTAL (Contract Regarding an Interim Supplement to Tanker Liability for Oil Pollution) is a cargo owners contract to provide supplemental compensation for tanker owners' cleanup costs and third-party damage claims after remedies available to claimants from other regimes have been exhausted. Member oil companies contribute to a fund based on each company's annual oil movements or transfers. The fund is maintained at between $3 million and $5 million. When the amount of money in the fund falls below specified levels, it is replenished by "calls" on the participants. CRISTAL became effective in 1971.

3. IMCO Civil Liability Convention

The IMCO CLC came into force in June 1975 and to date has been ratified by 34 nations. It imposes liability on ship owners for cleanup; it also covers third-party damage claims.

4. IMCO Fund Convention

The IMCO International Convention on the Establishment of an International Fund for Oil Pollution Damage (the Fund Convention), adopted in 1971, came into force in October 1978. The Fund Convention would supplement CLC. It would also indemnify tanker owners subject to CLC for a portion of their CLC liability. The size of the IMCO fund -- the money on hand to pay claims -- is determined by formula and will be maintained at between $3 million and $5 million.

When the voluntary regimes were initially developed, it was thought that they would no longer be needed when CLC and the Fund Convention came into force. But the IMCO conventions are only applicable to spills in the waters of or affecting the territory of nations that have ratified the convention. TOVALOP applies to any spill, no matter where in the world it occurs, as long as the tanker owner is a participant in TOVALOP. So the voluntary regimes will continue to play an important role in areas where governments have not yet ratified the IMCO conventions.

Levels of compensation for oil pollution by the voluntary plans and convention requirements are as follows:

- TOVALOP -- Now covers pollution damage including measures taken to mitigate damage or remove threat of damage up to the lesser of $147 per gross registered ton or $16.8 million per incident.
- CRISTAL -- Provides supplemental coverage to TOVALOP with maximum liability of $36 million per incident. There is a

provision for the membership to increase the limit up to $72 million if experiences indicate that the $36 million figure is inadequate.

- CLC -- Provides liability coverage, in those countries that have ratified the convention, up to a maximum of $16.8 million per incident (which is similar to TOVALOP limits).

- Fund Convention -- Initially provided liability coverage supplemental to CLC, in those countries that have ratified the convention, up to a maximum of $36 million per incident. Shortly after the convention came into force, the upper limit was raised to $54 million. Additionally, the convention granted to the fund the right to increase the limit to $72 million when such action was deemed appropriate.

The cost of compensating claimants for pollution damage has risen steadily and the limits adopted in 1969 need re-evaluation. In recognition of this problem, industry and the legal committee of IMCO have been studying existing limits with a view toward increasing the maximum limits. In this connection, the U.S. State Department convened a subcommittee meeting in early June 1981 for the purpose of developing recommendations to the IMCO assembly. The petroleum industry supports the efforts to increase the convention limits, but does not favor changes in TOVALOP and CRISTAL limits if these would reduce incentives for countries to ratify the convention.

The United States' record on ratification of IMCO-related international conventions is very good. The outstanding exception to this good record is the U.S. failure to ratify the 1969 CLC and the 1971 Fund Convention. The petroleum industry has consistently supported U.S. ratification of these two IMCO conventions since 1975, when implementing legislation for the CLC and Fund Convention was considered by Congress but not ratified.

The probability of U.S. ratification of these two conventions has declined in the recent past as a result of the <u>Amoco Cadiz</u> incident and other major spills. These spills spurred a move in the United States, France, and some other countries to increase liability limits well above those included in CLC and the Fund Convention.

The reasons for industry support for U.S. ratification are:

- Uniformity is the key to success in dealing with international problems. Oil pollution of the seas is an international problem and should be dealt with on a broad base of internationally agreed and accepted regimes.

  The United States played a leading role in development of these conventions. U.S. failure to ratify them over a 10-year period has tended to undermine support and delay ratification in other countries. Although the Fund

Convention entered into force in October 1978, there are still only 21 nations that have ratified it. Thus, if the United States chooses not to ratify these conventions, it would abandon an international responsibility and could be party to the collapse of these international pollution liability regimes.

- The ratification of the conventions would facilitate the international commerce of the United States by assuring a uniform international liability scheme and a broader market for obtaining this type of liability coverage.

V. Onshore Pollution Control and Prevention

A. Routine Wastewater Discharges

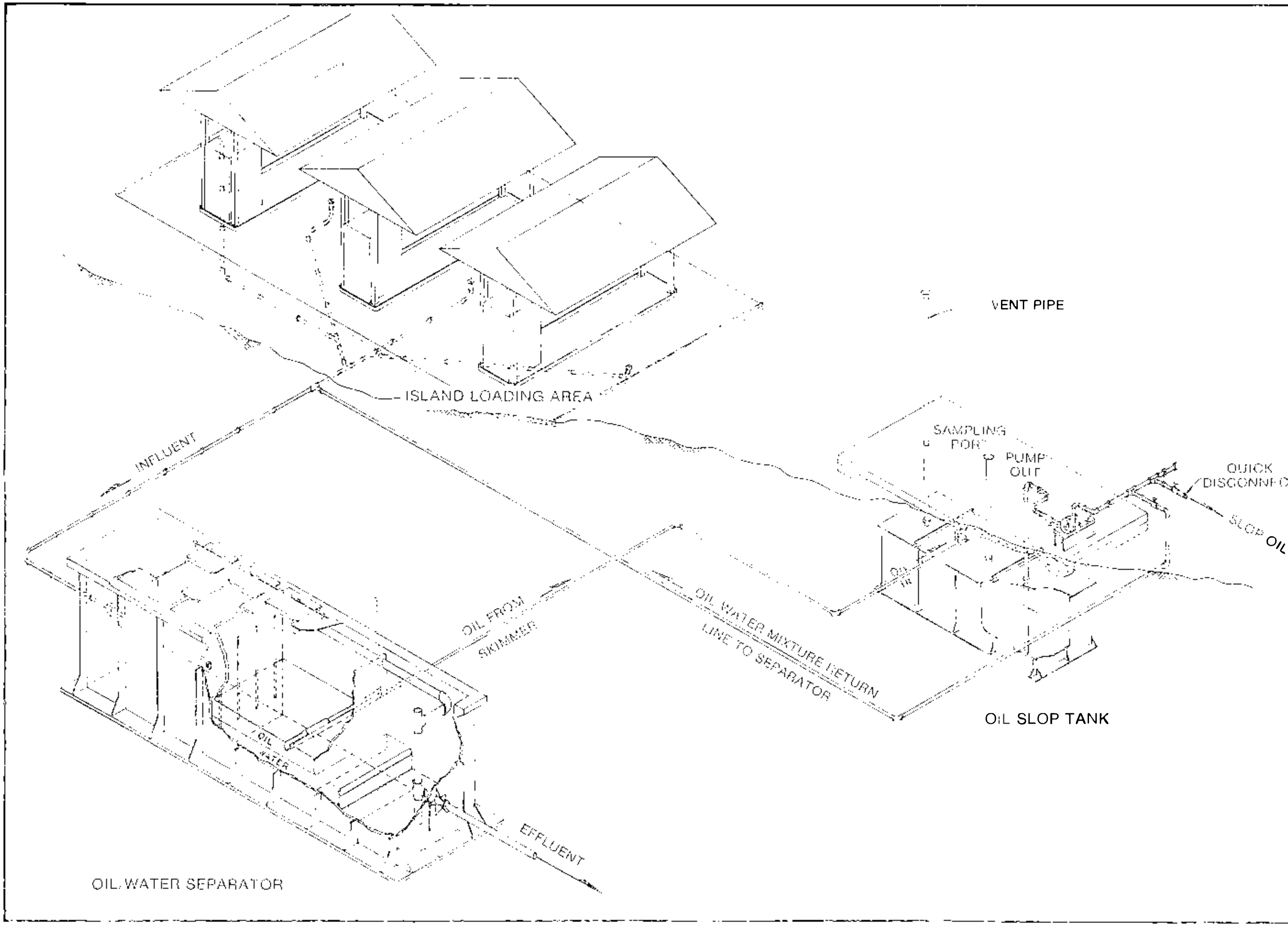
This section discusses the pollution control and prevention practices and federal/state regulations that are common to various routine operations and onshore facilities in the storage, transportation, and marketing segment. Under the Clean Water Act, facilities that treat and discharge their own wastewater to navigable waters of the United States are subject to NPDES permit requirements. Those facilities that discharge to sewers connected to municipal sewer plants do not require NPDES permits, but may have discharge restrictions imposed by the municipal sewer plant.

Water discharge from storge, transportation, and marketing facilities during normal operations originates from three main areas: surface runoff, oily water, and wash water.

Surface runoff water primarily originates from rainwater. If it becomes contaminated, it may require treatment by oil/water separation before discharge.

Oily water originating from the handling of liquid petroleum in the distribution system requires oil/water separation or further treatment, depending upon the particular application and degree of contamination. It originates from tanks, slab drains, drip pans, petroleum sump or sewer systems, and catch basins under loading racks for rail tank cars and tank trucks. A typical marketing terminal system is shown in Figure 97. In this figure, oily water is collected from catch basins under tank trucks at the loading areas. The oil/water mixture is gravity fed as the influent to an oil/water separator. Separation of the oil and water takes place in the separator, and oil is skimmed from the water surface and discharged to a slop tank for reclamation.

The separator effluent must comply with NPDES permit requirements Water requiring treatment from marine terminal operations, barges, and tankers is handled in a similar manner, depending upon the extent of contamination. Water from marine terminal applications may require further treatment such as air flotation and chemical flocculation.



SOURCE: AFL Industries.

Figure 97. Typical Marketing Terminal System.

Wash water from tank trucks, rail tank cars, barges, tankers, and stationary storage tanks may also require treatment before discharge water will meet applicable permit limitations. Wash waters from these activities is highly variable and can be expected to contain detergents, chemicals, O&G, and suspended solids. Commercial treatment systems are available for such individual applications that will normally produce high-quality discharge water. In some installations such treated water is recycled to eliminate the need for discharging.

In 1976, API published the results of a survey that had been undertaken to determine the physical and operating characteristics of 76 petroleum marketing terminals and the O&G content in their wastewater discharges.[41] The report concluded that with good housekeeping practices and a gravity oil/water separator (or its equivalent) a long-term mean O&G concentration of 17.5 mg/l was attainable.

1. NPDES Permits

The Clean Water Act prohibits the discharge of pollutants, unless authorized by permit. The permit program for wastewater discharge is known as the National Pollutant Discharge Elimination System. EPA was initially authorized to issue NPDES permits. However, the Clean Water Act provides that the authority be transferred to the state agencies, if they meet federal criteria. As of December 1980, 33 states had NPDES authority.

In the event that a state does not receive federal approval, an operator must apply for a permit from EPA and, in some cases, from both EPA and the particular state. Operators having facilities in more than one state must often apply for both federal and state permits.

EPA has not promulgated effluent limitation guidelines for petroleum storage, transportation, and marketing facilities. As a result, permit conditions were determined on a facility-by-facility basis by permit writers using "best professional judgment." Without uniform guidelines for consistency, the severity of permit conditions vary. Some permits specify limitations and sampling requirements for pH, biochemical oxygen demand, chemical oxygen demand, O&G, and total suspended solids. Other permits specify 30 ppm monthly average of O&G based on one grab sample per month, with enforcement monitoring requiring separate samples at least six hours apart and a violation occurring only if both samples exceed the 30 ppm average. Because in many cases grab samples are involved, some permits allow 10 percent of the sample results to be discarded for reporting purposes. In addition, no permit is required to discharge uncontaminated, untreated storm water.

2. Control Technology

To prevent surface runoff of contaminated discharge water, storage, transportation, and marketing bulk plants and terminals

are constructed through use of dikes, ditches, elevation grading, impoundments, and oil/water separation methods, to prevent pollution. Various methods of drainage control, containment, and oil/water separation treatment are used. In most cases, these facilities do not require highly technical solutions to the water discharge problem as exist in some refinery or processing applications.

Dikes or earthen berms are constructed wherever petroleum liquids are stored in above-ground tanks -- around tanks in pipeline tank farms, storage terminals, and marketing bulk plants. These dikes are designed to contain products spilled from the tankage and are sized to contain a maximum potential spill. The impounded water that is trapped within the dike as the result of water draws or storm water either percolates into the soil or is released through a drain pipe and valve under the dike. Where drain pipes and valves are installed, they are normally chained and locked in the closed position to ensure the integrity of the dike containment system.

Storage, transportation, and marketing facilities primarily rely upon the oil/water separators for wastewater treatment. An oil/water separator designed in accordance with API standards will in most cases produce acceptable discharge water in facilities where O&G is the primary contaminant.

Figure 98 illustrates a typical terminal system configuration for treating wastewater prior to discharge. In this example, a commercially available oil/water separator is used to recover petroleum liquids and release oil-free water for evaporation and occasional discharge. Oily water from tank water draw-off lines and the launcher/receiver, strainer, and slab drains flows into the oil/water separator. Rainwater that enters a tank settles through the stored oil and is drawn off from water collection points in the tank bottom. Drawing off water is a manual operation under visual observation. Withdrawal is stopped immediately at the first appearance of petroleum liquid, indicating that the water has been expelled. Other operational procedures, such as strainer cleaning, opening launcher and receiver barrels, and flushing of drain down slabs and drip pans also contribute oily water to the separator.

Oil is skimmed from the water surface in the separator, flowing to a recovered oil sump where it can be pumped back into a pipeline system or tank or sold for recovery. Treated water is discharged to a holding/evaporation basin. This allows for a visual check on the proper removal of free oil from the treated water. In arid areas, evaporation and percolation provide adequate disposal for the water. In non-arid areas the treated water is discharged to a surface drain system or other conveyance.

B. Spill Control Contingency Planning

Storage, transportation, and marketing facility operators are required by EPA regulations to maintain SPCC plans. Such plans are

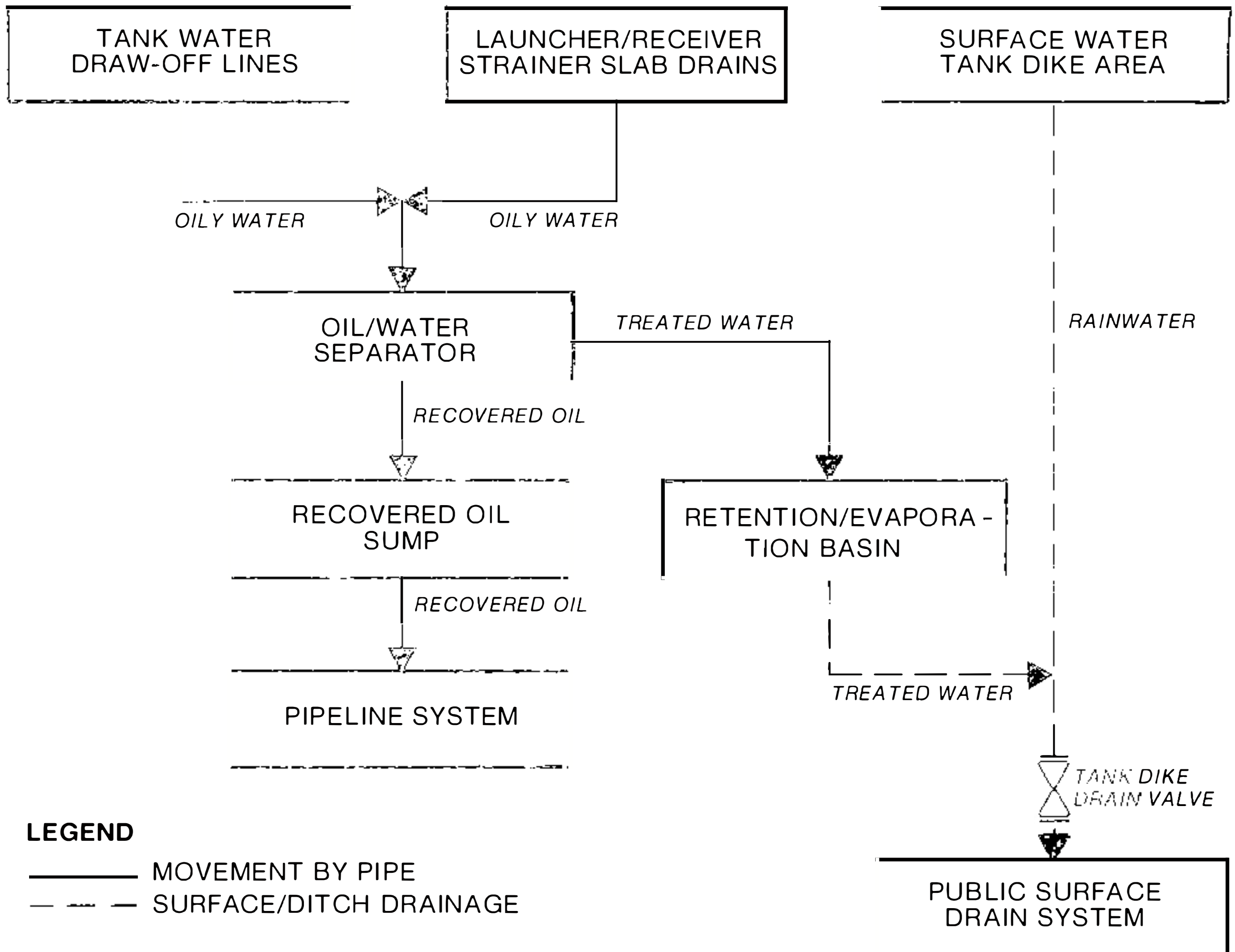


Figure 98. Typical Oil/Water Separator System.

to cover the basic information required for operators to respond to spills. A typical spill control plan:

- Establishes information required about nature of the emergency
- Instructs personnel in procedures for notification of company officials and catastrophe response teams
- Instructs personnel in notification requirements of proper state and federal agencies
- Lists emergency contractors for facility repair, spill containment, and cleanup
- Maintains required emergency equipment lists
- Instructs in spill containment and cleanup procedures.

In addition to developing SPCC plans, many operators of storage, transportation, and marketing facilities have formed or joined

oil spill contingency cooperatives. Group members are drawn from various industries and local government agencies who have a common concern to prevent and minimize hazards and pollution resulting from oil spills. Such groups are formed for mutual assistance, especially in areas highly susceptible and sensitive to oil spill hazards -- such as U.S. ports and inland waterways

These mutual aid groups meet periodically to share their knowledge of new oil spill technology and recent spill events, and frequently provide training in emergency preparedness. The mutual assistance groups usually prepare lists of emergency equipment that each member is willing to loan to another in case of an oil spill. They also will often agree to furnish manpower and assist a member in whatever way practical to minimize effects of oil spills in their particular areas. The group may also fund a cleanup contractor to be on a stand-by basis. Oil spill cooperatives are discussed in more detail in Chapter Six.

C. Pipelines

There are special considerations for pollution control and prevention from pipelines because spills can occur at any point along the many miles of pipeline used by the industry.

1. Design and Operating Practices

Facilities are designed in accordance with appropriate industry standards and codes in addition to state and federal regulations. The DOT regulations cover a large portion of the petroleum distribution system wherever it is classified as part of a common carrier. These regulations are intended to improve safety and minimize spills by establishing requirements for design, construction, and operation.

Code requirements were developed within the industry to ensure safety and stability of liquid pipelines. Many pipeline companies retain outside testing laboratories to check the quality of pipe during its manufacture by the pipe mill. Samples of pipe metal are physically and chemically analyzed. Finished pipe is subjected to hydrostatic pressure tests, to fluoroscopic and ultrasonic examinations of longitudinal welds, and to radiographic examination of girth welds. During and after construction of the line, the pipe is generally subjected to hydrostatic pressure tests with pressures that exceed maximum operating pressure by at least 25 percent.

Protective coatings are applied to line pipe during construction. During operation the line pipe and pump station equipment are further shielded against external corrosion by cathodic protection. Internal corrosion is combatted by regular use of internal scrapers, which sweep the water from low points in the line and clean the internal surface. If repairs are necessary, present practice is to cut out a cylinder and weld in a new cylinder or cover the pitted area with a welded full encirclement sleeve. At the same time, pipe in the area of the repair is cleaned and externally coated to provide protection from corrosion before backfilling.

Factors that may affect the life of uncoated pipe and thus affect the frequency of repairs are: adequacy of cathodic protection, inconsistency (excessive voids) in the soil adjacent to the pipe due to improper backfilling, foreign material and debris in the backfill, the proximity to extraneous electric currents, and the conductivity of the soil. These are some of the factors considered when specifying the coating for a pipeline and when designing the cathodic protection for that line.

Properly applied coating has a very long service life and is extensively used today to prevent corrosion in areas where external corrosion is a problem. Electric detectors are used during coating application to assure coating continuity. Before the pipeline is lowered into the ground, any gaps or weaknesses in the coating are patched. When repair records indicate corrosion problems have occurred on existing bare pipe, hot spot cathodic protection is provided as necessary. Line sections are replaced where repairs are not economical.

2. Construction Permits

Construction activities involving navigable waters or tributaries to navigable waters of the United States are regulated by the Clean Water Act, Section 404. Construction requiring dredge or fill in these waters for pipeline river or wetland crossings requires Corps of Engineers Section 404 permits. The U.S. Army Corps of Engineers will involve other federal, state, and local agencies and may conduct public hearings prior to permit approval.

The Corps of Engineers will evaluate the facilities' potential environmental impact to water resources and may require that special procedures and conditions be undertaken during construction to avoid contaminating the marine environment. Pipeline and terminal projects requiring Section 404 permits before construction can begin must determine if permit requirements are compatible with the economics of the site selection, the entire project, and the intended operation of the proposed facility.

3. Hydrostatic Testing

After construction of cross-country pipelines, DOT regulations require hydrostatic testing of the welded steel pipe. The hydrostatic test procedures are intended to verify the strength and integrity of the steel pipe. Test pressures depend upon the specified minimum yield strength of the pipe steel, intended operating pressures, and DOT requirements.

Hydrostatic testing is usually accomplished with water. The volume of water required for test purposes is directly related to the diameter of the pipeline and length of line segment being tested. Volumes may vary from several hundred barrels to several hundreds of thousands of barrels of water, depending upon the size of the pipeline project.

Disposal of the water after testing is an environmental consideration and requires state/local and possibly federal permits. Such disposal is a one-time occurrence after construction and not a normal operating requirement. Quality of the hydrostatic test water may be an issue because of possible treatment the water has undergone while being pumped into the pipeline. Hydrostatic test water could contain some of the following treatments:

- pH treatment
- Corrosion inhibitors
- Anti-freeze
- Bactericides.

A typical solution to disposal of hydrostatic test water is to construct evaporation holding ponds at points where water is drained from the pipeline. Sampling and testing of the water in the evaporation ponds can be accomplished before discharge, if ever required.

4. Protective Devices and Alarms

Numerous protective devices and alarms are an integral part of pipeline operations. Pipeline and storage terminals have remote tank gauging and tank high level alarms to alert operators to take action to prevent tank overflows. Pipeline temperatures, flow rates, and pressures are monitored and controlled to prevent pipeline ruptures. Automatic shutdown devices are installed on pumping equipment to prevent spills in the event of a failure of a pump seal. Such devices minimize operational upsets and prevent and detect accidental petroleum spillage.

5. Leak Detection

Pipeline terminal tank fill operations can be remotely monitored using automatic tank gauging equipment. Tank high-level alarms and shutdown switches can be used to prevent tank overflows. Tank levels and filling rates can be compared to flow meters to detect deviations from calculated filling or emptying rates to guard against spills. Similar leak detection systems can be applied to prevent spills when filling tank trucks, rail cars, barges, or even tankers. To prevent occurrence of spills, a computer control system will activate alarms or automatic shutdowns.

Computer models of pipeline systems are used to predict expected pipeline hdyraulic conditions. The computer also monitors actual pipeline flow conditions such as flow rate, pressure, temperature, density of liquids, and configuration of pump unit combinations. If actual conditions are in variance from the predicted hydraulic model, the computer can be set up to sound deviation alarms or even shut down and isolate the affected pipeline segment.

Other types of leak detection systems are available, such as visual television monitoring and instruments for detecting hydrocarbon liquids or vapors escaping from closed systems. Instruments to detect pressure surges created by small pipeline ruptures are also available for leak detection.

6. Training

Proper training of operations personnel is a fundamental part of an operator's program for water quality protection. Training is necessary to ensure that personnel have the necessary skills to operate equipment, conduct preventative maintenance, and make proper equipment repairs. In addition, it is important for training to include personnel response to abnormal operating conditions and emergencies plus training in spill containment and cleanup.

Comprehensive training programs that include testing and record keeping have the potential to reduce human error, thus minimizing operational upsets and reducing petroleum spills. Training in the area of both normal and abnormal operations is both highly desirable and a requirement of DOT regulations enacted in 1979 for common carrier pipeline facilities.[42]

The DOT requirements under Part 195 of the regulations require that each common carrier pipeline establish and conduct a continuing training program to instruct operating and maintenance personnel. Major requirements of this regulation include training in the following areas related to water quality protection:

- Carry out the operating, maintenance, and emergency procedures
- Know characteristics and hazards of the commodities transported
- Recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions or failures and commodity spills, and take appropriate corrective action
- Take steps necessary to control any accidental release of the commodity and to minimize the potential for fire, explosion, toxicity, or environmental damage
- In the case of maintenance personnel, safely repair facilities using appropriate special precautions
- At intervals of not more than one year, common carriers are to:
  - Review with personnel their performance in meeting objectives of the training program
  - Make appropriate changes to the program as necessary

- Verify that supervisors maintain a thorough knowledge of the carrier procedural manuals for operations, maintenance, and emergencies.

These DOT regulations are promulgated under the Hazardous Liquid Pipeline Safety Act of 1979. Enforcement of these regulations is by the Office of Operations and Enforcement, a part of the Materials Transportation Bureau of DOT.

7. One Call Notification Systems

In the past several years, some operators of liquid petroleum and gas pipelines have assisted in forming, and have become members of, one call notification systems.

The primary feature of a one call system is a central telephone contact number for contractors and member companies to call to report digging activities. Operators of the one call systems receive these calls and then notify member companies who have facilities in the affected areas. These companies are then able to dispatch personnel to the field to inspect, identify, and protect their facilities from damage, thereby minimizing spill potential.

D. Service Stations

Leaks from service station underground tankage offer the potential for serious harm to people, property, and the environment. Service stations are located for customer convenience and the greater the population density of the driving public, the greater the number of retail outlets to be expected. Even in semi-urban or rural areas, the retail outlets frequently are located in sites of considerable business activity rather than being isolated.

The loss of petroleum products may present significant additional problems to the community, including: disruption of business and home endangerment when vapors are found in buildings; explosions in sewers; contamination of groundwater supplies; fire/explosion hazards at the sewage treatment plant; deterioration of telephone cables and disruption of service; and fire at the loss site.

The petroleum industry is concerned that leakage of product from or water into service station tanks has a greater potential now than it did 10 years ago.[43] This is because a large number of underground, unprotected steel tanks and piping systems installed 15 to 25 years ago may be nearing the end of their lifespan. In response to this situation, the trend within industry has been to emphasize daily product inventory reconciliation and water checking at all service stations, immediately investigate all reported losses and conduct tank testing as deemed necessary, and repair leaking tanks with epoxy lining or replace them with noncorroding or cathodically protected corrosion-resistant tanks.

A 1977-1980 API leak study attempted to determine where leaks occur in the tank. Responses to the voluntary survey were received

on 1,546 leak incidents, including leakage of water into tanks. The majority of tank leaks were reported to develop in the lower portion of underground tanks. Of leaking tanks with submerged drop tubes, 27 percent had a leak directly beneath the tube. Procedures for inventory control and checking for water accumulation accounted for detection of 76 percent of the leaks found.

The petroleum industry's approach to preventing and controlling leaks from underground tanks is many-faceted, reflecting the complex nature of the problem:

- Changes in fire codes and state environmental regulations, to make daily inventory control the law, are encouraged.
- An educational training program stressing record keeping and maintenance of inventory control was prepared for use by facility owners and operators.
- Leakage training seminars for industry and government officials are conducted.
- Assistance is provided to communities attempting to locate the source of underground leaks.
- API prepared and published the following publications: "Industry Recommended Practices for the Prevention and Detection of Leaks from Underground Tanks and Pipes," "Underground Spill Cleanup Manual," "Installation of Underground Petroleum Storage Systems," and "Recommended Practice for Abandonment or Removal of Used Underground Service Station Tanks."

The principal materials and techniques used to prevent corrosion and detect leaks in underground storage tanks are: coatings, cathodic protection, fiberglass-reinforced plastic underground tanks, storage tank liners, and leak testing.[44]

Service stations in the United States with underground tanks use external coatings such as good quality epoxies, asphaltic paints, mastics, and hot-applied bituminous materials to prevent corrosion. Coatings reduce tank exposure to corrosive elements in the surrounding soil; however, some of these materials deteriorate with time and may be useful for only a few years. Corrosion occurs most often at breaks or flaws in the coating, which can be minimized by proper installation. Corrosion prevention is improved by cathodic protection, described below.

The cathodic protection technique protects underground storage tanks by preventing electrolytic corrosion caused by stray electrical currents. Connections are made to opposite ends of a storage tank and a small power source is connected, resulting in a polarized tank. The current passing through the tank interferes with, and reduces the effect of, any external electrical currents.

There are two basic types of cathodic protection commonly used to protect underground tanks, galvanic and impressed current. Cathodic protection, by means of galvanic or sacrificial anodes, is used for the protection of pipelines as well as for tanks. Knowledge of the soil resistivity, the quality of the coating material used, the exposed surface in contact with the soil, and the presence or absence of insulation is required for the calculation of the number of anodes needed. The most common type of anode is magnesium, although zinc anodes are used in low resistivity soils. The tanks are generally coated, because the number of anodes required increases with the unprotected area of the tank. During the past few years, "pre-engineered" cathodic protection has been developed, usually consisting of a tank with a galvanic anode on each end.

Impressed current protection works by passing DC current, supplied by an AC-DC transformer-rectifier, through the circuit, which consists of the tank, anodes, soil, and rectifier. The anodes are usually made from cast iron, graphite, or scrap steel. Because impressed current systems are adjustable over a wide output range, uncoated or bare tanks can be protected by using a high driving voltage.

Impressed current systems are relatively expensive, for they require, in addition to periodic inspection and maintenance costs, a constant source of current, which in some cases can be large. When there are other metallic structures in the area, the current may be picked up by these structures. These stray currents will leave the tank unprotected, which could lead to corrosion. For this reason, field tests are required to assure adequate protection.

Fiberglass-reinforced plastic storage tanks are an alternative to the use of steel tanks. Fiberglass-reinforced plastic is noncorrosive and when properly installed will last over 20 years.

Old tanks with leaks can be lined with epoxy resin. Epoxy coatings provide a solid, glass-hard inner protective wall that prevents corrosion and subsequent leaking. The process of epoxy lining a storage tank takes two days. The tank must first be emptied and aerated; it is then sand blasted to clean metal. The epoxy resin is applied and the tank is permanently sealed shut with a pressure-proof cover.

Daily inventory reconciliation can identify losses due to leaks. Several leak detection systems are commercially available as a contracted service or for purchase. These systems use various principles to determine a change in product level in the tank. These include observation of level change in an attached aboveground stand pipe, movement of fluid in a manometer, change of a buoyant force on a sensor, fluid flow past a thermister, and laser interferometry.

Each of these methods has one or more significant drawbacks that limits its ability to detect leaks reliably. Some methods require highly skilled operators for proper test set-up and for

correct data analysis. Certain test procedures result in higher than normal tank pressures, extensive set-up time, and high costs. Other systems are somewhat fragile for everyday field use. Still others give only a single end-of-test value. Data generated by all can be affected by temperature change, wind, or vibration. The ability to correctly recognize and compensate for such effects, as well as careful adherence to correct test procedures, determines success in locating leaking tanks.

WASTE MANAGEMENT

Industry practices continue to be developed and implemented to ensure proper handling of waste materials. Issues of concern include the proper handling of used lubricating oils and the future availability of adequate disposal capacity.

I. Applicable Laws and Regulations

Three pieces of recently enacted legislation have addressed different aspects of the waste management problem. These three laws are: RCRA; the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) (Superfund); and the Used Oil Recycling Act. All three have impacted the petroleum industry in different ways; RCRA and CERCLA are discussed in Chapter One of this report, and the Used Oil Recycling Act is discussed in the following section.

II. Waste Sources

A. Storage and Transportation

Waste materials generated in tanks and pipelines are similar to the oily wastes generated in refineries. Waste sources in storage and transportation include tank and pipeline cleaning, oily sludges from wastewater separator cleaning, and spill cleanup debris. The federal RCRA hazardous waste management program does not list storage or transportation wastes as hazardous; however, the RCRA program provides that wastes be tested to determine if they are hazardous due to specified ignitable, corrosive, reactive, or extraction procedure (EP) toxic criteria. Tests must be run on individual wastes as generated and some storage and transportation wastes from low flash tanks can exhibit the ignitable characteristic (flash less than 140°F) and some leaded gasoline storage tank sludges can exhibit the EP toxic characteristic. If and when these wastes exhibit any of the characteristics, they must be managed in accordance with the RCRA regulations. The RCRA regulations are discussed in more detail in Chapter Three.

Ocean tankers are also potential sources of waste materials. After one or two years of service, tankers typically go into drydock for inspection, maintenance, and refitting. Because cargo tanks must be clean and gas-free, they must be rigorously cleaned. These removed sludges may exhibit hazardous waste characteristics. In addition, many maintenance degreasing solvents are listed as

hazardous wastes and must be handled accordingly. Many of these wastes are handled at terminals and shipyards as discussed in the Offshore Pollution Control and Prevention section of this chapter.

B. Marketing

The recently enacted RCRA and Used Oil Recycling Act have caused the petroleum industry to focus its attention on the proper disposal of waste materials from the variety of marketing operations. Of particular interest is the disposal of used lubricating oils from service stations and other waste oils from industrial customers. In addition, the industry has continued to stress good housekeeping practices for its service stations to prevent the accumulation of used tires, batteries, and accessories from contributing to pollution of the area.

Used lubricating oils can be disposed of in a variety of ways. One successful way is by blending and burning the used lubricating oils as an industrial fuel oil. A 1974 API study, conducted at a Hawaiian Electric Company plant, concluded that burning dilute mixtures (up to 15 volume percent) of used crankcase oil was a feasible means of disposal.[45] The study also reported that maximum ground-level concentrations of lead were within acceptable levels at that time. A 1970 API study, reporting the results of a number of individual used oil burning tests, recommended that the amount of used oil in the fuel blend should not exceed 25 percent, to minimize combustion difficulties and to avoid air pollution problems.[46]

The Solid Waste Disposal Act was amended by enactment of RCRA, and was further amended on October 15, 1980, when Congress enacted the Used Oil Recycling Act to encourage the use of recycled oil "in a manner which does not constitute a threat to public health and the environment, and which conserves energy and materials."[47] Section 7 of the Act requires the promulgation by EPA of performance standards and other necessary regulations to protect the public health and environment. Section 8 of the Used Oil Recycling Act required EPA to make a report to Congress on their determination of whether the RCRA hazardous waste criteria (Section 3001) were applicable to waste oils.

EPA's January 16, 1981 report to Congress, Listing Waste Oil as a Hazardous Waste, contained the following estimates on used oil disposition:

Disposition	Percent
Burned as fuel	55
Used as road oil, dust suppressant, or other land application use	15
Rerefined to lube oil base stock	10
Disposed of in landfills or indiscriminately dumped	20
	100

EPA estimates that used oil quantities are 464 million gallons per year of automotive oils and 380 million gallons of industrial oils. The EPA report notes that there is considerable disagreement in the literature on used oil disposition and quantities, but believes that the above figures are consistent with most available data.

In its report to Congress, EPA concluded that waste unused oil spilled to land, and oily debris generated from cleaning up oil spills to land or surface water, are of substantial quantities and pose a significant risk to contaminate groundwater, and thus should be classified as hazardous wastes. In addition, EPA concluded that used automotive oils and certain industrial oils may contain other potentially toxic contaminants, such as trace metals, halogenated hydrocarbons, and polynuclear aromatics, and therefore should be designated as hazardous wastes.

API reviewed the EPA Report to Congress and in December 1981 sent a critique to the Agency. The API critique questions the scope of the report as it relates to the mandates of Section 8 of the Used Oil Recycling Act of 1980 and challenges the Scientific accuracy of the facts used to determine that certain used oils are hazardous wastes.[48]

In February 1981, Shell Oil filed a report under the requirements of 8(e) of the Toxic Substances Control Act (TSCA).[49] This "substantial risk notice" reported that used lubricating oils from gasoline engines caused malignant tumors in mice skin painting studies. These skin painting studies were sponsored by API, using a composite blend of 15 used gasoline engine oil samples.

Both the report to Congress and the TSCA 8(e) notification were used by EPA in drafting hazardous waste oil regulations under Part 266 of RCRA. The Part 266 waste oil regulations are presently an unpublished draft document.[50] It is expected that proposed regulations will be published in the Federal Register in 1982. The draft regulations incorporate the identical definition of hazardous waste oils as published in EPA's report to Congress; i.e., unused oils spilled to land and the oily debris from cleanup of spills to land or surface waters, used automotive oils, and used industrial oils. The regulations would apply to persons who store, treat, recycle, or dispose by thermal treatment of waste oils. In the draft regulations, special exemptions were given to service stations and collection centers. The anticipated regulations utilize a permit-by-rule approach with the exception of road oiling with waste oil, which will be considered on a case-by-case basis. Disposal of waste oil by means other than thermal treatment (e.g., landfilling) is regulated under Part 264 or 265 of RCRA. The regulations delineate administrative, performance, technical, and management requirements.

EPA has continued to give clear signals that it intends to regulate used oils as hazardous wastes. If this occurs, it will cause large impacts in the marketing areas with the possibility of little commensurate environmental benefit. This results from the possibility that regulatory entanglements of the hazardous waste

listing will actually discourage the recycling of used oils through increased paperwork, monitoring, record keeping, and testing requirements on used oil collectors.

Many states have or are considering legislation requiring oil marketers to accept used oil from "do-it-yourselfers." Many service stations and recycling centers now collect used oils and sell them to collectors for re-refining or burning.

The re-refining industry has not prospered in recent years because of a number of problems. Prior to 1965, there were about 165 re-refiners, while in 1980 there were only about 20. Among the problems that contributed to the decline were the 1965 Tax Law, environmental controls, and the government prohibition on the use of re-refined oils.

The 1965 Tax Law required re-refiners to pay a lubricating oil tax of $0.06 per gallon on the finished product, and many re-refiners ceased operation because they could not compete in the lube oil market. With the development of stringent environmental controls in the mid-1970's, even more re-refiners went out of business because they could not afford the costs of compliance. Later, more stringent regulations for waste disposal and landfill caused many more re-refiners to cease operations due to their inability to dispose of acid sludges generated by the re-refining process.

Although the government and the military used re-refined oils during World War II, they prohibited their use in the early 1960's for the following reasons:

- The increasing use of chemical additives in lubricating oils to enhance their performance created problems in re-refining to the extent that some re-refiners "cut corners" and did not produce high-quality products even though the technology to do so was known.

- The re-refiners were being squeezed by taxes, market limitations, and waste disposal problems, so that purchasers could not depend on consistent quality.

- Engine lubrication became more critical and required oils with special performance characteristics.

More recent federal legislation (e.g., the Used Oil Recycling Act of 1980) has addressed the re-refined oils problem and requires that the government and military approve their use provided that the re-refined oils meet specifications. This legislation, the need for energy conservation, and the increasing cost of crude oil has led to new interest in the re-refining industry.

The opportunity exists to increase the re-refining of used oils to enhance energy conservation without adverse effects to the environment. However, there are concerns that EPA's program to list used oils as hazardous wastes will actually discourage the recycling of used oils.

TABLE 57

Environmental Expenditures in Storage, Transportation, and Marketing -- 1971-1980
(Millions of Dollars)

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	Total 1971-1980
Capital Expenditures											
Air	$47	$24	$53	$127	$92	$66	$41	$38	$58	$107	$653
Water	30	30	39	56	109	73	58	51	54	88	588
Land and Other	17	22	17	43	326	191	109	22	15	28	790
Subtotal	$94	$76	$109	$226	$527	$330	$208	$111	$127	$223	$2,031
Administrative, Operating, & Maintenance Expenditures											
Air	$19	$18	$25	$46	$41	$40	$41	$41	$49	$73	$393
Water	26	21	23	33	39	59	50	58	54	63	426
Land and Other	12	13	13	13	11	17	132	29	23	27	290
Subtotal	$57	$52	$61	$92	$91	$116	$223	$128	$126	$163	$1,109
Total	$151	$128	$170	$318	$618	$446	$431	$239	$253	$386	$3,140

SOURCE: American Petroleum Institute, Environmental Expenditures of the United States Petroleum Industry, 1971-1980, 1981.

ENVIRONMENTAL EXPENDITURES

Environmental expenditure information collected by the API Environmental Expenditures Survey (see Table 57) shows that total 1980 pollution control costs for the storage, transportation, and marketing industry segments were $386 million, about 10 percent of the total pollution control expenditures for the entire petroleum industry.[51] For the 10-year period of 1971 to 1980, storage, transportation, and marketing pollution control expenditures totalled over $3 billion, about 15 percent of total petroleum industry pollution control expenditures.

A Battelle report, entitled The Cost of Environmental Regulations to the Petroleum Industry,[52] presents estimates of environmental control costs to the petroleum industry from 1965 through 1990. It shows the costs of existing and expected regulations and the incremental costs of specific controls. The costs include both capital expenditures and cash operating costs.

The domestic transportation sector's share of the total industry's environmental costs in 1990 is small, about 4 percent of the total, with anticipated 1990 annualized costs of $630 million. In the transportation sector, costs are as follows: 17 percent for air control; 70 percent for water; and 13 percent for other (e.g., Trans-Alaska Pipeline environmental efforts). The largest single cost, $262 million, resulted from specifications for new tankers and modification of existing tankers; contingency planning for spills cost $70 million, and various Alaska environmental impact work cost $80 million.

The distribution and marketing sectors' share of the total industry's environmental costs in 1990 is also small, about 3 percent of the total, with anticipated 1990 annualized costs of $510 million. In 1990, costs of $190 million are expected to occur due to surveillance and capital recovery of the installations made in the mid-1970's. Water cleanup is about 36 percent of the whole, related to developing SPCC plans and treating runoff water at terminals and bulk plants. The most costly pollution control regulations in the air category are for the control of vapors from terminal, bulk plant, and service station gasoline storage tanks. These constitute 27 percent of the total, or $135 million in 1990.

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CHAPTER FIVE

PRODUCT USE

CHAPTER FIVE

PRODUCT USE

INTRODUCTION

In addition to the environmental impacts of petroleum industry operations as such, the use of petroleum products has some environmental impacts. Compliance with environmental requirements, whether mandatory or voluntary, has affected the composition and distribution of petroleum products. This section presents an overview of those products that have minor or negligible environmental significance, and a more detailed discussion of the areas in which the impacts have been much greater.

Table 58 contains a partial list of the classes of products marketed by the industry and reflects the scope and relative quantities of the products manufactured. Although 87 percent of all products are included in the "fuels" category, other products are important to the national economy. Lubricants (0.9 percent of total products), for example, literally "keep the wheels of industry turning" with materials to meet almost every friction-reducing need. Petroleum-derived chemical products (4.0 percent of total products) fill chemical market needs.

The major environmental impacts from the use of petroleum products as fuel are discussed under the heading of Fuels, and are subdivided into the impacts from stationary sources and mobile sources. Following that section is a discussion of the impacts of lubricants and asphalts.

FUELS

As indicated in Table 58, approximately 87 percent of petroleum products, exclusive of natural gas, is consumed as fuel. In addition, 20.1 billion cubic feet of natural gas was consumed in 1980.[1] The use of petroleum products as fuel generates emissions of sulfur oxides (SO_x), nitrogen oxides (NO_x), particulates, carbon monoxide (CO), and unburned hydrocarbons.

The complete oxidation (burning) of any carbonaceous material converts the material into carbon dioxide and water. When the oxidizing medium is air (approximately 80 percent nitrogen content) and the mixture is high in oxygen (i.e., lean) accompanied by high temperature, some NO_x will be formed. Unless the mixture ratio is well controlled and good mixing is maintained, there will be areas of flame that are low in oxygen (rich in fuel) and in which particulate carbon or smoke will be formed. Any sulfur in the mixture will be oxidized to SO_x, most of the nitrogen compounds will be oxidized to NO_x, and any metals or other elements will form their respective oxides.

TABLE 58

Major Petroleum Product Use by Sector -- 1980*

Fuel Products	Millions of Barrels	Percentage of Total
Industrial Sector		
Distillate Fuel Oil	257	4.1
Residual Fuel Oil	258	4.1
Liquefied Gases	169	2.7
Motor Gasoline	28	0.4
Kerosene	21	0.3
Other	304	4.9
Natural Gas†		
Residential and Commercial Sector		
Distillate Fuel Oil	353	5.7
Residual Fuel Oil	86	1.4
Liquefied Gases	136	2.2
Kerosene	38	0.6
Motor Gasoline	20	0.3
Natural Gas†		
Transportation Sector		
Aviation Gasoline	13	0.2
Distillate Fuel Oil	401	6.4
Jet Fuel	387	6.2
Motor Gasoline	2,362	37.9
Residual Fuel Oil	132	2.1
Liquefied Gases	2	<0.1
Electric Utility Sector		
Distillate Fuel Oil	39	0.6
Jet Fuel	2	<0.1
Residual Fuel Oil	438	7.0
Other	1	<0.1
Non-Fuel Products		
Industrial Sector		
Ethane	123	2.0
Liquefied Gases	111	1.8
Lubricants	30	0.5
Petrochemical Feed Stocks	251	4.0
Petroleum Coke	17	0.3
Special Naphthas	36	0.6
Wax	6	0.1
Miscellaneous	39	0.6
Natural Gas†		
Residential and Commercial Sector		
Asphalt and Road Oil	146	2.4
Transportation		
Lubricants	28	0.4
Total§	6,234	100.0

*Source of data: Energy Information Administration, 1980 Annual Report to Congress, Volume II.

†Natural gas not included in totals.

§Totals may not add due to rounding.

I. Stationary Sources

Petroleum products are widely used in industrial plants for electric power generation, domestic and commercial heating, and manufacturing processes. When used as fuels they generate gaseous emissions as part of the combustion process. Thus, such plants are known as stationary sources. Evaporative emissions can also occur in commercial processes. The stationary plant emissions that receive primary attention because of their impact on atmospheric quality are SO_x, particulates, NO_x, CO, and unburned hydrocarbons.

Coal is the major fuel used in power generation and its use for this purpose is expected to increase; however, petroleum fuels, in either gaseous or liquid form, will continue to provide a large part of power generation fuel needs. Recently, environmental restrictions imposed on the burning of coal have reduced its attractiveness as a fuel. These restrictions resulted from the New Source Performance Standard (NSPS) for sulfur emissions from new coal-burning electric utility steam-generating units. This standard required a percentage reduction in emissions; thus, stack gas desulfurization units were necessary, no matter how low the sulfur content of the coal. Nuclear plant development has lagged in its rate of growth, but is expected to gradually reduce petroleum fuel needs for power generation in the future. Fuel combustion stationary sources currently are the largest single source of SO_x and particulate air pollutants (see Tables 59 and 60). Other air pollutants include NO_x, CO, and unburned hydrocarbons, although the amounts of CO and hydrocarbons emitted from stationary combustion sources are insignificant compared with mobile source emissions (see Tables 61 and 62).

Emissions from domestic and commercial heating units are those commonly associated with the burning of fossil fuels. Although the total quantities are less than those from power generation, their effect on ground-level concentration in some cases can be greater, due to dispersed low-level emission sources.

A. SO_x Emissions and Control Techniques

1. Emissions

SO_x emissions occur primarily from stationary source fuel combustion and other industrial processes. It has been estimated that in 1979, SO_x from fuel oil combustion represented approximately 16 percent of the total SO_x from all fuel combustion.[2] From 1970 to 1979, emissions of SO_x decreased by 13 percent (Table 63).

Sulfur enters the atmosphere as air pollutants in the form of sulfur dioxide (SO_2), sulfur trioxide, hydrogen sulfide (H_2S), carbon disulfides, carbonyl sulfide, sulfuric acid, and particulate sulfates, and as natural emanations in the form of H_2S and sulfates. About one-third of the sulfur comes from anthropogenic (man-made) sources, mostly in the form of SO_2, and the remainder from natural processes.

TABLE 59

National Estimates of Sulfur Oxide Emissions -- 1970-1979
(Million Metric Tons Per Year)

Source Category	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Transportation										
Highway Vehicles	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4
Aircraft	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Railroads	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Vessels	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Other Off-Highway Vehicles	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Transportation Total	0.7	0.6	0.6	0.6	0.6	0.6	0.8	0.8	0.8	0.8
Stationary Source Fuel Combustion										
Electric Utilities	15.6	15.4	15.6	17.0	16.5	16.5	17.1	16.9	16.0	16.0
Industrial	3.6	3.0	2.9	2.6	2.3	2.2	2.1	2.0	2.0	2.3
Commercial/Institutional	1.3	1.3	1.3	1.3	1.2	1.0	1.2	1.1	1.1	1.0
Residential	0.6	0.6	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3
Fuel Combustion Total	21.1	20.3	20.2	21.3	20.4	20.0	20.7	20.3	19.4	19.6
Industrial Processes	6.4	5.9	6.5	6.5	5.7	4.6	4.4	4.3	4.1	4.1
Solid Waste Disposal										
Incineration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Open Burning	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solid Waste Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous										
Forest Fires	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Burning	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous Organic Solvent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous Total	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Total	28.3	26.9	27.4	28.5	26.7	25.2	25.9	25.4	24.3	24.5

SOURCE: U.S. Environmental Protection Agency, *National Air Pollutant Emission Estimates, 1970-1979*, March 1981.

TABLE 60

National Estimates of Particulate Emissions -- 1970-1979
(Million Metric Tons Per Year)

Source Category	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Transportation										
Highway Vehicles	0.9	1.0	1.0	1.1	1.1	1.0	1.1	1.1	1.1	1.1
Aircraft	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Railroads	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Vessels	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Other Off-Highway Vehicles	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Transportation Total	1.3	1.4	1.4	1.5	1.5	1.3	1.4	1.4	1.4	1.4
Stationary Source Fuel Combustion										
Electric Utilities	4.1	3.6	2.9	2.9	2.6	2.4	1.9	1.8	1.7	1.5
Industrial	2.8	2.1	1.4	1.1	1.0	0.8	0.7	0.7	0.6	0.6
Commercial/Institutional	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Residential	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Fuel Combustion Total	7.3	6.1	4.6	4.3	3.9	3.5	2.9	2.9	2.7	2.5
Industrial Processes	10.2	9.6	9.4	8.5	7.0	5.5	4.9	4.4	4.4	4.3
Solid Waste Disposal										
Incineration	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Open Burning	0.7	0.5	0.4	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Solid Waste Total	1.1	0.9	0.7	0.6	0.6	0.6	0.4	0.4	0.4	0.4
Miscellaneous										
Forest Fires	0.7	0.9	0.7	0.7	0.8	0.6	0.9	0.7	0.7	0.8
Other Burning	0.4	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Miscellaneous Organic Solvent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous Total	1.1	1.2	0.9	0.9	1.0	0.7	1.0	0.8	0.8	0.9
Total	21.0	19.0	17.0	15.8	14.0	11.6	10.6	9.9	9.7	9.5

SOURCE: U.S. Environmental Protection Agency, *National Air Pollutant Emission Estimates, 1970-1979*, March 1981.

TABLE 61

National Estimates of Carbon Monoxide Emissions -- 1970-1979
(Million Metric Tons Per Year)

Source Category	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Transportation										
Highway Vehicles	79.0	79.4	80.9	79.7	74.6	73.5	73.0	71.4	70.3	65.9
Aircraft	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
Railroads	0.3	0.2	0.3	0.3	0.3	0.2	0.3	0.3	0.3	0.3
Vessels	1.2	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.6	1.5
Other Off-Highway Vehicles	7.3	7.0	6.8	6.6	5.8	5.7	5.8	5.7	5.5	5.9
Transportation Total	88.7	88.8	90.1	88.8	82.9	81.6	81.4	79.7	78.6	74.5
Stationary Source Fuel Combustion										
Electric Utilities	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Industrial	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Commercial/Institutional	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Residential	1.0	0.9	0.7	0.6	0.6	0.7	0.7	0.8	0.9	1.0
Fuel Combustion Total	1.8	1.7	1.6	1.5	1.5	1.6	1.6	1.7	1.8	1.9
Industrial Processes	9.0	8.8	8.4	8.6	8.1	6.9	6.6	6.6	6.3	6.3
Solid Waste Disposal										
Incineration	2.7	2.3	2.2	2.1	1.9	1.8	1.5	1.5	1.4	1.4
Open Burning	3.7	2.7	2.1	1.7	1.5	1.3	1.2	1.1	1.1	1.1
Solid Waste Total	6.4	5.0	4.3	3.8	3.4	3.1	2.7	2.6	2.5	2.5
Miscellaneous										
Forest Fires	5.1	6.7	5.2	4.5	5.6	4.0	6.4	5.1	5.0	5.5
Other Burning	1.9	1.6	1.1	0.9	0.9	0.8	0.7	0.7	0.7	0.7
Miscellaneous Organic Solvent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous Total	7.0	8.3	6.3	5.4	6.5	4.8	7.1	5.8	5.7	6.2
Total	112.9	112.6	110.7	108.1	102.4	98.0	99.4	96.4	94.9	91.4

SOURCE: U.S. Environmental Protection Agency, National Air Pollutant Emission Estimates, 1970-1979, March 1981.

TABLE 62

National Estimates of Volatile Organic Compound Emissions -- 1970-1979
(Million Metric Tons Per Year)

Source Category	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Transportation										
Highway Vehicles	10.6	10.5	10.5	10.0	9.2	8.8	8.6	8.3	8.0	7.2
Aircraft	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Railroads	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Vessels	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
Other Off-Highway Vehicles	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7
Transportation Total	12.1	12.0	12.0	11.4	10.6	10.2	10.1	9.8	9.5	8.8
Stationary Source Fuel Combustion										
Electric Utilities	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Industrial	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial/Institutional	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Fuel Combustion Total	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Industrial Processes	10.3	10.0	11.0	11.3	10.9	9.8	10.7	11.2	12.3	12.4
Solid Waste Disposal										
Incineration	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Open Burning	1.3	1.0	0.7	0.6	0.5	0.5	0.4	0.4	0.4	0.4
Solid Waste Total	1.8	1.5	1.1	1.0	0.9	0.9	0.8	0.8	0.8	0.8
Miscellaneous										
Forest Fires	0.7	0.9	0.7	0.6	0.7	0.5	0.9	0.7	0.7	0.7
Other Burning	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Miscellaneous Organic Solvent	2.2	2.0	2.1	2.0	1.9	1.7	1.6	1.6	1.8	1.6
Miscellaneous Total	3.2	3.2	3.0	2.8	2.8	2.3	2.6	2.4	2.6	2.4
Total	27.7	27.0	27.4	26.8	25.5	23.4	24.4	24.4	25.4	24.6

SOURCE: U.S. Environmental Protection Agency, National Air Pollutant Emission Estimates, 1970-1979, March 1981.

TABLE 63

Summary of National Emission Estimates -- 1970-1979
(Million Metric Tons Per Year)

Year	TSP	SO_x	NO_x	VOC	CO
1970	21.0	28.3	19.1	27.7	112.9
1971	19.2	26.9	19.6	27.0	112.6
1972	17.0	27.4	10.7	27.4	110.7
1973	15.8	28.5	21.2	26.8	108.1
1974	14.0	26.7	20.8	25.5	102.4
1975	11.6	25.2	20.2	23.4	98.0
1976	10.6	25.9	21.8	24.4	99.4
1977	9.9	25.4	22.4	24.4	96.4
1978	9.7	24.3	22.7	25.4	94.9
1979	9.5	24.5	22.6	24.6	91.4
Change 1970-1979	-54.8%	-13.4%	+18.3%	-11.2%	-19.0%

SOURCE: Environmental Protection Agency, National Air Pollutant Emission Estimates, 1970-1979, March 1981.

SO_2 has been a major pollutant ever since the first burning of large quantities of soft coal and the first smelting of copper sulfide ore. Since the turn of the century, estimated SO_2 emissions from coal burning have increased 363 percent; from petroleum combustion, 864 percent; and from smelting, 707 percent. Coal still accounts for the largest portion of total worldwide SO_2 emissions.[3]

As shown in Tables 59 and 64, SO_x emissions from the combustion of sulfur-containing coal and residual fuel oil by electric utilities account for more than half of the total emissions from all anthropogenic sources. Between 1970 and 1979, utility use of coal increased about 64 percent and residual oil use increased about 50 percent. Emissions from utilities have increased only slightly, because fuels with lower sulfur content have been used to the extent that they were available. Flue gas desulfurization systems had seen only limited use, but by the late 1970's enough units were in service as required by NSPS to prevent additional increases in electric utility emissions. The 1979 electric utility emissions would have been approximately 5 percent higher without the operation of flue gas desulfurization controls. SO_x emissions from other fuel combustion sectors decreased during the decade, primarily due to less coal burning by these consumers, i.e., oil replacing coal.

TABLE 64

Sulfur Oxide Emissions from Fuel Combustion in Stationary Sources -- 1970-1979
(Thousand Metric Tons Per Year)

Source Category	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Coal										
Electric Utilities	14,150	13,910	14,260	15,490	15,010	15,120	15,690	15,270	14,330	14,520
Industrial	2,790	2,280	2,150	1,870	1,560	1,590	1,330			
Residential/Commercial	510	480		300	300	220	220			230
Coal Total	17,450	16,670		17,660	16,870				15,770	
Fuel Oil										
Electric Utilities	1,440	1,450	1,370	1,560	1,520	1,360	1,430			
Industrial		590			650					
	3,460									
Natural Gas										
Electric Utilities	0	0		0		0		0	0	
Wood										
Industrial	30	30	30	20		30				
Other Fuels										
Industrial	110	90	100	90	100	90	120	120	110	120
Residential	20	20	10	10	10	10	10	10	10	10
Other Fuels Total	130	110		100						
	21,070	20,190								19,530

SOURCE: U.S. Environmental Protection Agency, National Air Pollutant Emission Estimates, 1970-1979, March 1981.

A moderate increase in coal use for power generation and a slow revitalization of the nuclear power industry are expected. Residual fuel oil will continue to be a major source of fuel for the forseeable future. However, its share of the market is expected to decrease significantly.[4]

2. Control Techniques

A variety of approaches have been taken for controlling SO_x emissions from stationary sources, including fuel substitution, fuel desulfurization, and flue gas desulfurization.

a. Fuel Substitution

Fuel substitution is the replacement of high-sulfur fuels with low-sulfur fuels. This method would be the simplest approach if the availability and supply of low-sulfur fuels were ample. Conversion to nuclear, geothermal, or hydropower energy for electric power generation could also greatly reduce the emission of SO_2 from power plants. An added benefit of fuel substitution is the possible reduction of particulate emissions if low-sulfur oil replaces coal. Switching to electric heating could be considered a fuel substitute if it is produced from a noncombustion process such as nuclear energy. Otherwise, the SO_x emissions would simply be relocated.

Limitations on increases in emissions by the Prevention of Significant Deterioration and nonattainment regulations of the Clean Air Act are responsible for proposed increased use of low-sulfur fuels, especially natural gas. However, the limited supplies of low-sulfur fuels and natural gas cannot begin to meet the nation's requirements for fossil fuels. Use of natural gas by industries and power plants is limited by the availability of new reserves of natural gas and its needs for home heating and cooking. The demand for low-sulfur crude oils and low-sulfur fuels is also increasing in other countries, making it more difficult for the United States to obtain naturally occurring low-sulfur crude oils. Priorities have already been established for low-sulfur fuel usage in certain regions of the nation. Local sulfur-in-fuel regulations, prompted by public concern, have been responsible for some fuel switching. Since 1974 the trend to switch from coal to oil firing has been reversed. Most boilers capable of firing coal are doing so and essentially all new fossil fuel boilers for power generation are coal fired, as required by the Fuel Use Act.

b. Fuel Desulfurization

Fuel desulfurization of petroleum middle distillates and lighter fractions was developed to satisfy requirements for improved product quality. The more costly desulfurization of heavier distillates was developed later. Desulfurization of high-sulfur residual stocks is now possible but requires rigorous, expensive processing, limited to certain low-metal-content residuals.

The largest single source of SO_2, coal, is the most difficult to desulfurize. Coal preparation techniques (e.g., coal washing)

are used with varying results, depending upon the specific type of coal used. More large, commercially operating coal liquefaction and gasification facilities could increase supplies of low-sulfur fuel in the early 1990's.

Stationary sources that burn petroleum fuels contribute approximately 16 percent of the total SO_2 emitted to the atmosphere.[5] Since nearly 90 percent of the SO_x produced by these petroleum fuels comes from burning the heavier residual fraction, it would seem logical to concentrate efforts on residual fuel desulfurization. Direct desulfurization of high-sulfur residuals can presently be accomplished only on certain low-metal-content residuals, consequently limiting the volume of low-sulfur material obtained from this process. Low-sulfur residual is also obtained by topping naturally occurring low-sulfur crude oils. Residual fuels produced from this type of operation contain 0.5 percent sulfur level or less, depending upon crude oil source. The volume of material available from these low-sulfur crude oils is limited due to their source, principally North and West Africa, and the ever-increasing worldwide competition for these low-sulfur crude oils.

The most common method of obtaining low-sulfur fuels is by blending high-sulfur residual with desulfurized low-sulfur vacuum distillates. This technique is used to supply most of the low-sulfur residual fuel to the East Coast markets. Desulfurization of the overhead from vacuum distillation of reduced crude oil can produce fuel having a sulfur content as low as 0.3 percent; however, the use of only this portion, with no back blending of residual, would greatly reduce the limited supply of low-sulfur fuel.

In some areas low-sulfur heavy fuels are produced by direct desulfurization or by delayed coking and solvent deasphalting followed by blending with a vacuum gas oil. The Caribbean refineries are the major source of low-sulfur fuel for the East Coast market, and West Coast refineries primarily supply local markets. In recent years, these refineries have invested heavily in desulfurization processes to satisfy the demand for lower sulfur fuel oils.

Use of catalysts allows direct hydrodesulfurization of residual fuels to the low-sulfur level. However, due to its high cost, this process is still limited in application to selected lower metals fuel. Most of the heavy fuel oil desulfurization facilities were constructed between 1968 and 1974. Desulfurization capacity in 1980 was 2.0 million barrels per day (MMB/D), 11.1 percent of the total crude oil capacity of 18.0 MM/D.[6] Capacity is still adequate to supply the current demand for lower sulfur fuel oil. A description of desulfurization processes is found in the Industry Operations section of Chapter Three.

Desulfurization of refinery fuel gas is required in most cases to remove sulfur compounds. The NSPS for refineries requires reduction of H_2S in fuel gas to 10 grains/100 standard cubic feet. For these reasons, burning of refinery fuel gas contributes very little to the overall SO_2-emission impact on air quality.

c. Flue Gas Desulfurization

Progress in developing flue gas desulfurization processes has been slow, due to the magnitude and complexity of the problem, yet this process has received widespread attention, especially for coal-burning power generation facilities. Although impressive advances in research have been made, the high costs, operational problems, and waste disposal problems associated with stack gas cleanup techniques continue to limit the application to large new or modified high-sulfur coal burning sources. Future application of flue gas desulfurization will depend upon the performance of the current generation of prototype units. For fuel oil burning sources, use of low-sulfur fuels, in lieu of flue gas cleanup, continues to be the more economically attractive practice and should continue to satisfy the demand as coal becomes an increasingly dominant fuel for power generation facilities.

B. Particulate Emissions and Control Techniques

1. Emissions

The solid particulate matter emitted to the atmosphere includes both organics and inorganics from fuel combustion, charred cellulose and ash from incineration, oxidized gasoline additives (mainly lead compounds), mineral dust from rock crushing and from asphaltic and Portland cement batching plants, metallurigical fumes, catalyst fines, and other miscellaneous dusts from industrial processes. Some finely divided liquid aerosols from fuel combustion, asphalt blowing, and sulfuric and phosphoric acid manufacture also are a part of total particulate emissions.

Of the 9.5 million metric tons of particulates emitted in the United States during 1979, 4.3 million tons were emitted from industrial processes other than combustion, 2.5 million tons were emitted from stationary combustion, 1.4 million tons from transportation, and 0.4 million tons from incineration and open burning, as shown in Table 60. During the period between 1970 and 1979, emission of particulates in the United States decreased from 21 million metric tons to 9.5 million metric tons (Table 63). Major factors in this reduction were the installation of control equipment on industrial processes and on coal-fired stationary combustion sources. As shown in Table 65, coal firing is still the major source of particulates from stationary combustion, accounting for 1.8 million metric tons per year. In 1970, coal firing emitted 6.5 million metric tons. Fuel oil combustion was responsible for 0.3 million tons, essentially unchanged over the period. Natural gas combustion emitted less than 0.1 million tons.

Two types of particulates are emitted from fossil fuel combustion -- inorganic particulates, which are the residue of the ash constituents in the fuel, and carbonaceous particulates, which are the result of incomplete combustion. Gas and distillate fuels do not yield significant amounts of ash, so they do not emit any inorganic particulates. Residual fuels contain ash-forming materials in quantities up to 0.1 percent by weight. Coal contains as

TABLE 65

Particulate Emissions from Fuel Combustion in Stationary Sources -- 1970-1979
(Thousand Metric Tons Per Year)

Source Category	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Coal										
Electric Utilities	3,960	3,470	2,780	2,750	2,490	2,290	1,740	1,600	1,570	1,400
Industrial	2,360	1,640	980	750	580	490	420	350	350	360
Residential/Commercial	210	200	160	160	160	130	110	110	110	100
Coal Total	6,530	5,310	3,920	3,660	3,230	2,910	2,270	2,060	2,030	1,860
Fuel Oil										
Electric Utilities	110	110	110	130	130	110	120	140	140	120
Industrial	50	40	50	50	50	30	50		50	50
Residential/Commercial	100	100	110	100	90	80	90		80	80
Fuel Oil Total	260	250	270	280	270	220	260		270	250
Natural Gas										
Electric Utilities	20	20	20	20	20	10	10	10	10	20
Industrial	40	40	40	40	40	30	30	30		30
Residential/Commercial	30	30	30	30	30	30		30	30	30
Natural Gas Total	90	90	90	90	90	70	80	70	70	80
Wood										
Industrial	310	290	270	250	250	200	190	190	180	170
Residential	50	50	40	40	40	60	60	80	100	120
Wood Total	360	340	310	290	290	260	250	270	280	290
Other Fuels										
Industrial	40	40	40	40	40	40	40	30	30	30
Residential	10	10	10	10	10	10	10	10	10	10
Other Fuels Total	50	50	50	50	50	50	50	40	40	40
Fuel Combustion Total	7,290	6,040	4,640	4,370	3,930	3,510	2,910	2,730	2,690	2,520

SOURCE: U.S. Environmental Protection Agency, National Air Pollutant Emission Estimates, 1970-1979, March 1981.

much as 10-20 weight percent ash residue. Most of this residue is emitted as fine particulates.

In general, emission factors for particulate air pollutants provide a reasonably good indication of the average emissions from a large number of installations, but are not precise indicators of the levels of emissions from a given installation.

2. Control Techniques

The general methods of controlling particulate emissions include improved combustion, flue gas cleaning, fuel substitution, and fuel modification.

a. Improved Combustion

Improved combustion is the most effective method for reducing particulate emissions from liquid or gaseous fuels. Better combustion can be achieved by improved atomization of liquid fuels and by improving the mixing of air and fuel to reduce the possibility that some portion of the fuel will be burned with insufficient oxygen. A number of burners have been developed over the past few years to give clean combustion with a minimum of excess air to maximize efficiency. These burners range from small burners for domestic heating to power generation burners.

b. Flue Gas Cleaning

Flue gas cleaning is most commonly used for particulate control with coal firing because of the large amount of inorganic ash in coal. Additionally, these techniques are used in the firing of high ash residual oil:

- Electrostatic precipitators are commonly used flue gas cleaning devices. They have very high efficiency, being capable of achieving over 99 percent removal. They also have very high cost and operating problems, however, which limit their use on small installations. Conventional low-temperature precipitators tend to lose efficiency with low-sulfur fuels, but high-temperature precipitators have been developed to overcome this problem.

- Wet scrubbers are capable of removing a significant amount of particulates when they are installed for SO_2 control. The collection efficiency of these devices is proportional to the energy input. Since high-energy devices are expensive to install and operate, there has been a tendency to install wet collectors of limited efficiency.

- A baghouse is preferred over a scrubber for collection of dusts and fumes. A baghouse ensures virtually complete collection of almost any dust or fume, whereas only the best scrubbers ensure good collection efficiency. On the other hand, if mists of hygroscopic particles are present in the gas, then a scrubber is preferable to a baghouse.

A settling chamber is a low-efficiency, low-cost, low-pressure-drop gas cleaning device. Most coal-fired power generation boilers include a hopper in which gas velocity is relatively low so that some of the particles settle out.

- Large-diameter cyclones are more efficient than settling chambers and have a wide range of efficiencies, depending upon the type of equipment used. They are best suited for particles in the 15- to 40-micron range; however, high-efficiency cyclones can collect particles in the 5-micron range. The tendency of the particles to agglomerate, forming larger sizes, eventually results in poor operation due to plugging or excessive accumulation on the walls of the equipment.

- Multiple small-diameter cyclones are used on mechanical draft combustion units, either as precleaners for electrostatic precipitators or as final cleaners. Their use is limited, however, because of the high pressure drop that they require.

c. Fuel Substitution and Modification

Switching from coal firing to oil firing or from either to gas firing will reduce particulate emissions on a given boiler. Prior to 1974, a large number of power generation units made such switches. In many cases the primary reason was to reduce SO_x emissions, but the particulate reduction occurred as a side effect.

In recent years, however, the trend has reversed. Many of the boilers that are capable of doing so have switched back to coal, primarily due to the wide difference in cost between oil and coal. Where gas is available and is cheaper than residual fuel oil (as in 1981), it is used preferentially, giving a significant reduction in particulate emissions. However, fuel availability and price are far more important determinants of which fuel is used than is particulate control.

Studies on the opacity of emissions from plants burning liquid fuels found that the fuels produced 0.2 to 1.2 micron size sulfate ash particulates. The opacity of these plumes exceeded 40 percent, and operation with supplementary natural gas was needed to reduce the opacity to acceptable levels. Only by using a premium low-sulfur, low-ash content liquid fuel were the plants able to produce a plume below 40 percent opacity. Visible emissions standards as stringent as 20 percent opacity maximum are now in effect in some areas. To meet these standards some operators use low-sulfur fuel even where other regulations do not require it.

One of the major benefits of desulfurized fuels is that they contain substantially lower amounts of ash and asphaltenes Most of the low-sulfur crude oils are low in both of these materials.

To the extent that nuclear plants or hydroelectric or geothermal units can be used to meet electric power demand, they

constitute a fuel substitution that reduces particulate emissions. As with changes among fossil fuels, however, economic and supply considerations other than particulate emissions determine whether they are used.

C. NO_x Emissions and Control Techniques

1. Emissions

Emissions of man-made NO_x are essentially caused by combustion processes. Stationary source combustion processes are the largest source, with transportation producing the bulk of the remainder (Table 66). Between 1970 and 1979, emission of NO_x increased from 19.1 million metric tons per year to 22.6 million metric tons per year. Both transportation and stationary combustion sources increased, but toward the end of the period the vehicle emissions dropped slightly as the result of control devices.

Within the stationary source combustion category, coal-fired utility boilers are the largest source followed by gas-fired industrial uses (see Table 67). Fuel oil firing accounts for a significant portion of the total NO_x emissions although its contribution is decreasing as the use of fuel oil decreases.

Petroleum products make a contribution to total U.S. NO_x emission in two major ways: transportation fuel and industrial fuel combustion. Transportation fuel use emits far more NO_x than do industrial processes.

In combustion processes, NO_x is generated by two mechanisms: (1) direct fixation of nitrogen in the combustion air and (2) oxidation of fuel nitrogen. Mechanism 1 produces more NO_x as combustion temperature increases and, therefore, its product is usually called thermal NO_x. Mechanism 2 is relatively independent of temperature. Its product is usually referred to as fuel NO_x. The percentage of fuel nitrogen that is emitted as fuel NO_x is a function of the nitrogen content of the fuel and of the oxygen concentration in the flame. In the combustion of fuels with significant nitrogen concentrations (i.e., heavy fuel oil and coal), both mechanisms make a significant contribution to the total. In large boilers without NO_x controls, the level of NO_x in the flue gas can range from 100 to 1,000 parts per million (ppm), with typical levels being about 200 ppm for gas firing, 400 ppm for oil firing, and 600 ppm for coal firing. Smaller units have considerably lower levels in the flue gas because they operate with a lower temperature in the firebox

2. Control Techniques

There are two general categories of control techniques for NO_x from stationary combustion sources -- combustion modification and flue gas removal systems. The combustion modification techniques work by reducing the peak temperature in the combustion zone and/or limiting oxygen availability during the initial stages of

TABLE 66

National Estimates of Nitrogen Oxide Emissions -- 1970-1979
(Million Metric Tons Per Year)

Source Category	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Transportation										
Highway Vehicles	5.2	5.7	6.3	6.6	6.4	6.4	6.7	6.8	6.9	6.7
Aircraft	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Railroads	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Vessels	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Other Off-Highway Vehicles	1.2	1.2	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.5
Transportation Total	7.2	7.7	8.4	8.7	8.6	8.6	9.0	9.1	9.4	9.2
Stationary Source Fuel Combustion										
Electric Utilities	5.1	5.3	5.7	6.2	6.1	6.1	6.6	7.1	7.1	7.5
Industrial	4.4	4.3	4.4	4.4	4.2	3.9	4.2	4.2	4.2	4.1
Commercial/Institutional	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.4
Residential	0.4	0.4	0.4	0.4	0.3	0.3	0.4	0.4	0.4	0.3
Fuel Combustion Total	10.4	10.5	11.0	11.5	11.1	10.7	11.7	12.2	12.2	12.3
Industrial Processes	0.8	0.8	0.8	0.8	0.8	0.7	0.8	0.8	0.8	0.8
Solid Waste Disposal										
Incineration	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Open Burning	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Solid Waste Total	0.4	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Miscellaneous										
Forest Fires	0.2	0.2	0.2	0.1	0.2	0.1	0.2	0.2	0.2	0.2
Other Burning	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous Organic Solvent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous Total	0.3	0.3	0.3	0.1	0.2	0.1	0.2	0.2	0.2	0.2
Total	19.1	19.6	20.7	21.2	20.8	20.2	21.8	22.4	22.7	22.6

SOURCE: U.S. Environmental Protection Agency, National Air Pollutant Emission Estimates, 1970-1979, March 1981.

TABLE 67

Nitrogen Oxide Emissions from Fuel Combustion in Stationary Sources -- 1970-1979
(Thousand Metric Tons Per Year)

Source Category	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Coal										
Electric Utilities	3,380	3,460	3,690	4,090	4,130	4,270	4,710	5,030	5,070	5,560
Industrial	680	550	530	470	440	470	430	410	420	460
Residential/Commercial	40	40	40	40	50	40	40	40	50	50
Coal Total	4,100	4,050	4,260	4,600	4,620	4,780	5,180	5,480	5,540	6,070
Fuel Oil										
Electric Utilities	650	780	950	1,110	1,050	980	1,050	1,220	1,150	980
Industrial	160	160	170	190	180	140	200	230	220	210
Residential/Commercial	440	440	450	450	410	380	430	420	410	380
Fuel Oil Total	1,250	1,380	1,570	1,750	1,640	1,500	1,680	1,870	1,780	1,570
Natural Gas										
Electric Utilities	1,070	1,090	1,090		940	860	840	870	870	960
Industrial	3,290	3,380	3,440	3,510	3,360	3,040	3,270	3,270	3,250	3,180
Residential/Commercial	310	320	330	320	310	320	330	310	320	330
Natural Gas Total	4,670	4,790			4,610	4,220	4,440	4,450	4,440	4,470
Industrial	180	170	170	160	170	190	200	190	200	210
	0	0			0	0	0	0	0	0
Wood Total	180	170	170		170	190	200	190	200	210
Other Fuels										
Industrial	60	50	60	50	60	60	70	70	60	70
Residential	50	50			40	40	40	40	40	30
Other Fuels Total	110	100	110	100	100	100	110	110	100	100
Fuel Combustion Total	10,310	10,490	10,970	11,430	11,140	10,790	11,610	12,100	12,060	12,420

SOURCE: U.S. Environmental Protection Agency, National Air Pollutant Emission Estimates, 1970-1979, March 1981.

combustion. The flue gas removal techniques inject ammonia, which is a specific reducing agent for NO_x.

a. Combustion Modification

- Low excess air operation is the simplest type of combustion modification, where it can be applied. It has an added advantage in that reducing excess air improves boiler efficiency. Generally, it requires installation of additional instrumentation and improved combustion controls to permit operation at a minimum excess air level without causing smoke or CO emissions. It can provide up to 20 to 30 percent NO_x reduction.

- Staged combustion may be used in various forms. Basically, the initial stage of combustion is carried out with less than stoichiometric air with additional air being added later to complete combustion. In the first stage, fuel nitrogen is converted to nitrogen instead of NO_x. Peak flame temperature is also lower than in conventional burners. Various methods are used for injecting the second stage air. In multiple burner boilers some burners may be operated rich and others lean so that the overall mixture is at the desired excess air level. Or some burners may be operated with air only. The excess air mixes with the rich flames down stream after initial phases of the combustion are completed. A version that requires considerable boiler modification operates all burners fuel rich and then adds secondary air through special ports above the flame zone. Staged combustion can give up to 50 percent NO_x reduction.

- Flue gas recycle is used to reduce peak flame temperature and thus minimize thermal NO_x. Cooled flue gas is mixed with combustion air. This technique requires considerable modification of existing boilers, including duct work burner modifications and increased fan capacity. It is not effective for reducing fuel NO_x, so it may give only 5 to 10 percent NO_x reduction with coal or oil firing.

- Steam or water injection can be used to cool the flame in the same way as flue gas recycling. However, the loss of the latent heat of the water reduces boiler efficiency, so this technique is not usually used in a boiler. In gas turbines, where the effect is less pronounced, water injection is more common.

- Low NO_x burners have come on the market in the past few years. They are constructed to give limited mixing of air and fuel in the first part of the flame, with additional air being inducted into the flame as combustion progresses, which gives the effect of two-stage combustion. These burners are reported to give up to 30 to 40 percent NO_x reduction, but the level of reduction varies widely with the application.

b. Flue Gas Removal Processes

- Thermal $DeNO_x$ is a process in which ammonia is injected into the flue gas within the boiler at a point where the temperature reaches about 1,800° F. The ammonia reacts selectively with the NO_x, reducing it to nitrogen and water. This process requires considerably more investment than most combustion modification techniques and the injection temperature is critical. If the ammonia is injected at too low a temperature it may pass through unconverted; at too high a temperature it increases NO_x. The thermal $DeNO_x$ process gives 50 to 70 percent reduction in NO_x and may be used in conjunction with combustion modification techniques to give an even higher overall reduction.

- Selective catalytic reduction is a similar process in that ammonia is used to reduce the NO_x. However, the ammonia is injected at a lower temperature (600-800°F) and a catalyst is used to carry out the reaction. This temperature range corresponds to the economizer outlet on most boilers. Because of the ducting and catalyst cost this process requires even more investment than thermal $DeNO_x$. However, it can give as much as 90 percent NO_x reduction. The process has been thoroughly demonstrated for gas-fired utility boilers, but as of this time it is just being tested for use with coal and oil combustion. Catalyst forms that will not plug due to the particulate load in the flue gas are being developed. The investment cost for catalytic reduction is generally considered too high to be practical for most industrial boilers.

c. Stationary Engines

In general, the NO_x emission control techniques used on stationary engines are similar to the ones used on automobiles. This includes spark retard, exhaust gas recycle, and catalysts. The primary NO_x control technique for stationary gas turbines is water injection.

D. CO Emissions and Control Techniques

1. Emissions

Most atmospheric CO is produced by the incomplete combustion of fuels used for transportation, power generation, industrial processing, and space heating (Table 61).

The concentration of CO in urban areas varies widely with time and location. Typical values ranging from 10 to 15 ppm have been reported in several metropolitan areas.[7] CO has long been considered a toxic pollutant, and for some time it was assumed that the only source of CO was fuel combustion. Recent studies, however, have indicated some important natural sources of CO.

Nationally, the quantity of CO emissions from oil- and gas-fired stationary combustion sources is insignificant compared to the 91.4 million metric tons emitted from all sources. Even coal-fired sources are estimated at less than 1 percent of the total U.S. CO emissions.

CO is formed when carbonaceous fuels are burned with insufficient oxygen. Low cooling rates and lean fuel/air mixtures will lower CO emissions. Emission factors are used for estimating CO emissions from various kinds of stationary combustion sources.[8]

When coal-, oil-, or gas-fired stationary combustion equipment is operated with insufficient air supply, CO emission rates can be considerably greater than emissions from well-adjusted units. Under these conditions, oil-fired and coal-fired units emit dense smoke, while maladjusted gas-fired equipment seldom emits visible smoke.

2. Control Techniques[9]

For minimum CO emissions, the combustion equipment should be designed for rapid reaction rates and long retention times. Various techniques for CO control are discussed below:

(1) Fuel substitution or switching does not seem justified, since CO emissions from boilers and furnaces are only a fraction of the total, despite the fuel burned.

(2) Plant relocation is rarely justified, for the same reason as in (1) above.

(3) Gas cleaning techniques are available that promote conversion of CO to CO_2 or absorb CO in amines and special copper liquids or by use of catalysts. However, those commercial processes have not been applied to cleaning CO from stationary combustion source gases.

(4) Good operating practices are the most sensible control technique.

- A well-adjusted gas-fired boiler may emit less than 1 ppm of CO but the same boiler may emit more than 50,000 ppm (5 percent) if insufficient combustion air is supplied. Insufficient air always causes CO formation and too much air may do the same. A proper fuel/air ratio adjustment is of major importance for reducing CO emissions from stationary combustion sources. Flue gases from the best-designed combustion unit may contain substantial concentrations of CO if insufficient air is provided for combustion. CO emissions also increase when excessive air is admitted to cool combustion temperatures below the optimum for maximum oxidation of fuel and CO. As a rule of thumb, coal- and oil-fired units may be adjusted for 10- to 12-percent CO_2 on a dry basis, and natural-gas-fired

units may be adjusted for 8- to 10-percent CO_2 on a dry basis. Since many units are designed to perform best at values outside these ranges, the combustion equipment manufacturer or other combustion experts should be consulted on proper fuel/air ratio adjustments for individual combustion units.

- Firing in excess of the design rate is perhaps the greatest cause of CO emissions from stationary combustion sources.

- Short residence times tend to increase CO in the flue gas due to less time for complete combustion. Proper residence time also allows the use of less excess air.

- High temperature is desirable up to about 2,800°F, where dissociation of CO_2 into CO becomes noticeable. Rapid cooling and low oxygen concentration tend to hinder the recombination of CO_2 and thus increase CO emissions.

- The degree of atomization is of prime importance in the proper functioning of an oil burner.

Proper maintenance by all concerned parties will be the best method of CO control from these combustion sources. In addition, two types of automatic combustion-control equipment are designed to minimize CO emissions by automatically adjusting fuel supply under varying load demand, and correcting and controlling the proper fuel/air ratio.

E. Hydrocarbon and Organic Emissions and Control Techniques

1. Emissions

The principal man-made sources of hydrocarbon and organic emissions in the United States are petroleum industry operations and product use. Hydrocarbon emissions from stationary source fuel combustion are minor in comparison to the total from transportation and other sources (see Table 62). A significant source of emissions is the use of organic solvents derived from petroleum, representing some 6 percent of the total emissions and eight times the amount from stationary fuel-burning sources.

2. Control Techniques

Similar to the control for CO in fuel combustion sources, a well-maintained and well-operated unit will prevent significant releases of hydrocarbons. Maintenance of the burner system, for example, is important to ensure proper atomization and subsequent minimization of any unburned combustibles.[10] Hydrocarbon emissions are directly related to the three common combustion parameters of time, temperature, and turbulence. Thus, adequate combustion time, high temperature, and a high degree of fuel/air turbulence will reduce hydrocarbon emissions, increase combustion efficiency, and reduce fuel consumption.

3. Organic Solvents

Organic solvents are derived mainly from petroleum sources and are used in a variety of industries, such as printing, chemical, drug, and pharmaceutical. Rubber and plastic manufacturing also involve the use of organic-solvent-based adhesives. Coatings such as paint, varnish, and lacquer are composed of a large percentage of organic solvents, which evaporate during and after application. Degreasing and drycleaning operations emit vapors from the use of organic solvents. (The impact of solvents in asphalt road surfacing material will be described later.) Control techniques commercially available may be divided into five general classifications: incineration, adsorption, absorption, condensation, and the use of substitute (nonphotochemically reactive) materials.

State Implementation Plans in most states, as required under the Clean Air Act, call for at least 80 percent reduction in volatile organic compound (VOC) emissions from the use of organic solvents. This requirement normally applies to ozone nonattainment areas. However, some states have applied the control strategy statewide.

II. Mobile Sources

A. Automotive Mobile Source Trends -- Emissions and Control Techniques

About half of the petroleum products consumed are used as transportation fuels, and about half of that amount for automobiles. Other modes of transportation consume petroleum fuels in much lesser proportions; i.e., trucks (26 percent), aircraft (8 percent), marine vessels (7 percent), railroads (3 percent), pipelines and other transportation uses (3 percent), and buses (1 percent).

Each product impacts the environment according to its physical properties, combustion characteristics, and volume of use. For example, CO and hydrocarbon emissions come mostly from gasoline-fueled automobiles, while particulate, NO_x, and SO_x emissions come mostly from diesel combustion. Aircraft, marine, railroad, and bus emissions vary, but have little environmental impact because of their proportionately low product volume use. Lead emissions, once an important environmental concern, are no longer a major issue as a result of the lead phasedown regulations and the increased demand for unleaded gasoline.

Since 1971, several events have occurred that are key both to the impact of transportation fuel use on the environment and to the effects of environmental regulations on the composition of products. Only one of these events, the market development for unleaded gasoline, which resulted from the widespread adoption of catalytic exhaust emission controls, had been predicted. All other events have occurred as a consequence of new areas of national concern which have developed since 1971.

After the oil embargo of 1973-1974 and the subsequent sharp rise in oil prices, the domestic passenger vehicle population began a fundamental shift from heavy, traditional passenger units to lighter, more fuel efficient passenger cars and light trucks. The impact of this change is reflected in legislation that established a schedule of minimum values for the average fuel economy of new vehicles, as shown in Table 68.

TABLE 68

Corporate Average Fuel Economy Standards -- 1978-1985*

Model Year	Passenger Cars (MPG)	Light Duty Trucks 4x2 (MPG)	4x4 (MPG)	Combined (MPG)	GVW†
1978	18	None	None	--	--
1979	19	17.5	15.8	--	≥6,000
1980	20	16.0	14.0	--	≥8,500
1981	22	16.7	15.0	--	≥8,500
1982	24	18.0	16.0	--	≥8,500
1983	26	19.5	17.5	19.0	≥8,500
1984	27	20.3	18.5	20.0	≥8,500
1985	27.5	21.6	19.0	21.0	≥8,500

*Abstracted from Pocket Reference, Technical Services, Environmental Activities Staff, GM Technical Center, April 1, 1981.

†Gross vehicle weight.

Meeting this schedule has challenged the domestic motor industry with perhaps the biggest peacetime conversion in its history, but it is significant that in recent years the market demand for fuel efficient cars has been sufficient to encourage most manufacturers to exceed their Corporate Average Fuel Economy (CAFE) requirements by a considerable margin. In addition, for the first time in the domestic passenger car market, vehicles powered by diesel engines have been introduced.

The trend towards diesel-powered vehicles is significant, and is expected to continue, subject to health and safety precautions. Not only is the diesel engine a more efficient energy conversion device (especially in light-duty service) but a gallon of diesel fuel contains about 11 percent more energy than does a gallon of gasoline. Thus, it offers manufacturers the option of serving the market for larger vehicles, while at the same time meeting similar CAFE targets. A much higher percentage of crude oil is now converted to automotive gasoline than to automobile diesel fuel, but this constraint is not expected to be limiting in the trend toward diesel powered automobiles in the next decade.

The shifts in the composition of the vehicle population support the trends shown in Figure 99. The environmental implications of this shift are significant, since for any given control methodology, gross emissions from transportation vehicles are dependent upon the volume and type of fuel consumed.

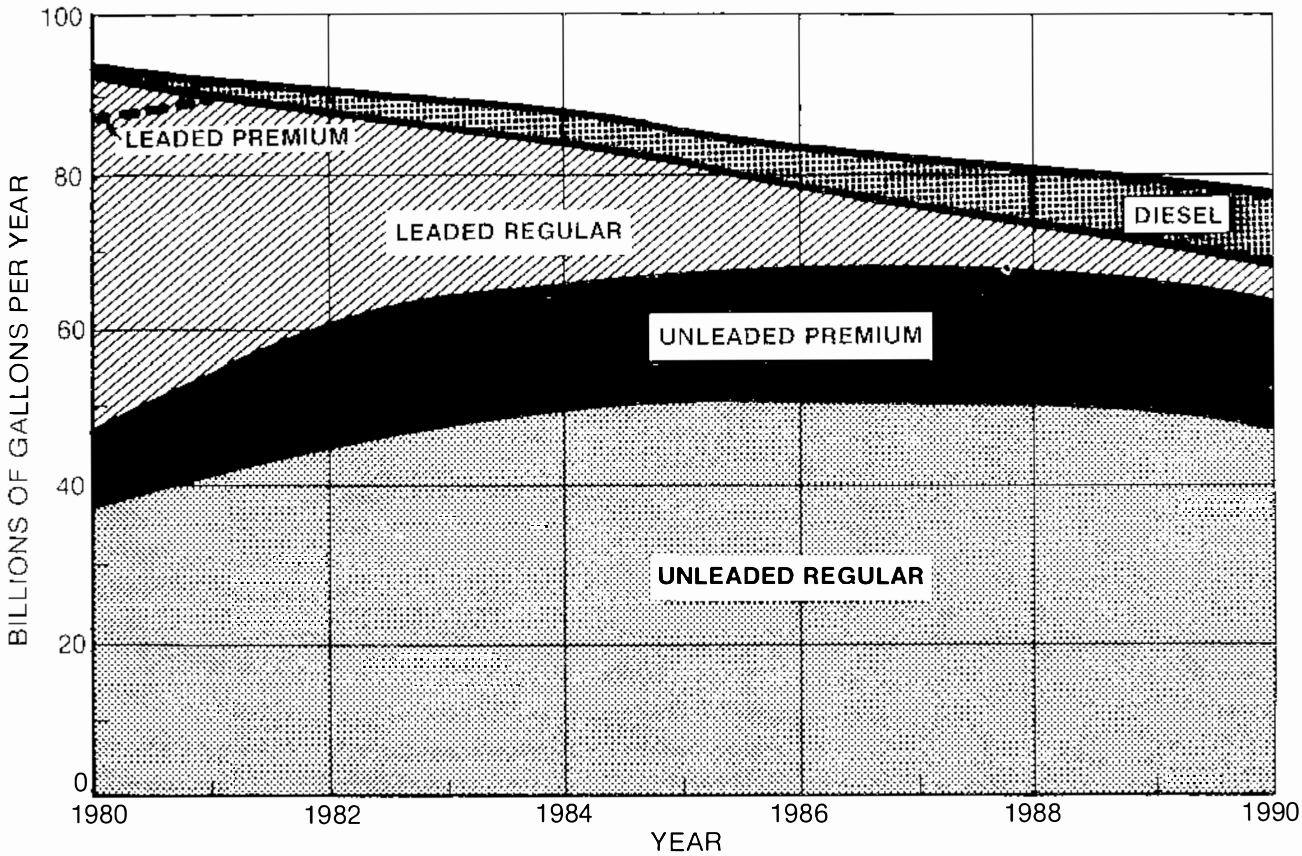

Figure 99. Gasoline and Diesel Consumption for Passenger Cars and Light Duty Trucks.

SOURCE: Sun Company, Inc., and General Motors Corp., 1981.

As mentioned previously, stringent statutory emission standards led to the adoption of catalytic control systems for most new vehicles, starting with the 1975 model year. To accommodate the fueling of these vehicles, the Environmental Protection Agency (EPA) provided for the general distribution of unleaded gasoline through almost all gasoline service stations, effective July 1, 1974.

Vehicles certified by EPA for use only with unleaded gasoline are fitted with filler necks that have restrictive inserts that would not accept the larger dispensing nozzles that must be used for leaded gasoline. Thus, vehicle misfueling (and consequent catalyst destruction) has not yet appeared as a major problem in maintaining the integrity of the new motor vehicle emission control methodology. A number of industry studies, an EPA study, and a California Air Resources Board study (of 13,000 motorists) all found low misfueling levels, ranging from 2 to 6 percent.[11]

Initially, unleaded gasoline was required to meet a 91 octane minimum specification by the Research method. Later, as it became recognized that the octane requirements of the vehicle population were better represented by an index consisting of the average of ratings obtained by the Research (R) and Motor (M) methods, an (R+M)/2 index minimum of 87 was added. The (R+M)/2 index is the number posted on dispensing pumps today. The 87 octane (index) unleaded gasoline approximates previous leaded premium gasoline before the lead was added.

This requirement for unleaded gasoline tends to limit the availability of gasoline, and in part accounts for the growth in refinery processing facilities experienced during the decade of the 1970's. Reforming capacity has increased during the decade from 2.7 MMB/D to 3.8 MMB/D. Catalysts that produce higher product octane have been developed and used throughout the industry. Moreover, the refining of high-octane-fuel blending components reduces gasoline yield compared to the case where similar antiknock performance can be achieved through the use of lead.

At the same time, fuel efficiency can be improved if engines can be calibrated for higher octane fuels. However, with increased production of higher octane fuels comes an increase in refinery fuel consumption. Thus, beyond a certain octane level, net fuel savings will decline. It has been estimated that at this optimum octane level, the net fuel saved due to leaded fuel is 6.5 percent greater than with unleaded fuel.[12]

A new aspect of fuel utilization relates to advanced vehicle computer control systems that can accommodate a knock sensor as a feedback element. These systems have the capability of utilizing a wider range of octane quality, since they typically are calibrated for the higher octane fuels. Fuels of lower octane are accommodated by automatic retardation of the spark timing to avoid continuous knock, but at the sacrifice of some fuel economy.

The first oxidation catalysts appeared in the 1975 model year, two years after the nadir of what had been a trend of seriously declining fuel economy (see Figure 100). To some extent, this departure from the previously used systems of "engine modifications" to meet emission control standards permitted a recalibration of the engine to restore some of the lost performance and economy. At the same time, increasingly more stringent emission control standards have taken a toll in fuel economy, as can be seen by comparing fleet fuel economy histories for similar cars manufactured to meet U.S. standards (for 49 states) and the previously more stringent California standards (see Table 69).

Future emission controls, by virtue of the computer control systems previously mentioned, will utilize so-called three-way catalysts not visualized in 1971. In a narrow range of air/fuel ratios around 14.8:1, the relationship of oxygen, CO, hydrocarbons, and NO_x in the exhaust is such that all three pollutants can be controlled to very low levels with a single catalyst. Another feedback sensor, this time used to measure oxygen in the exhaust stream, is used.

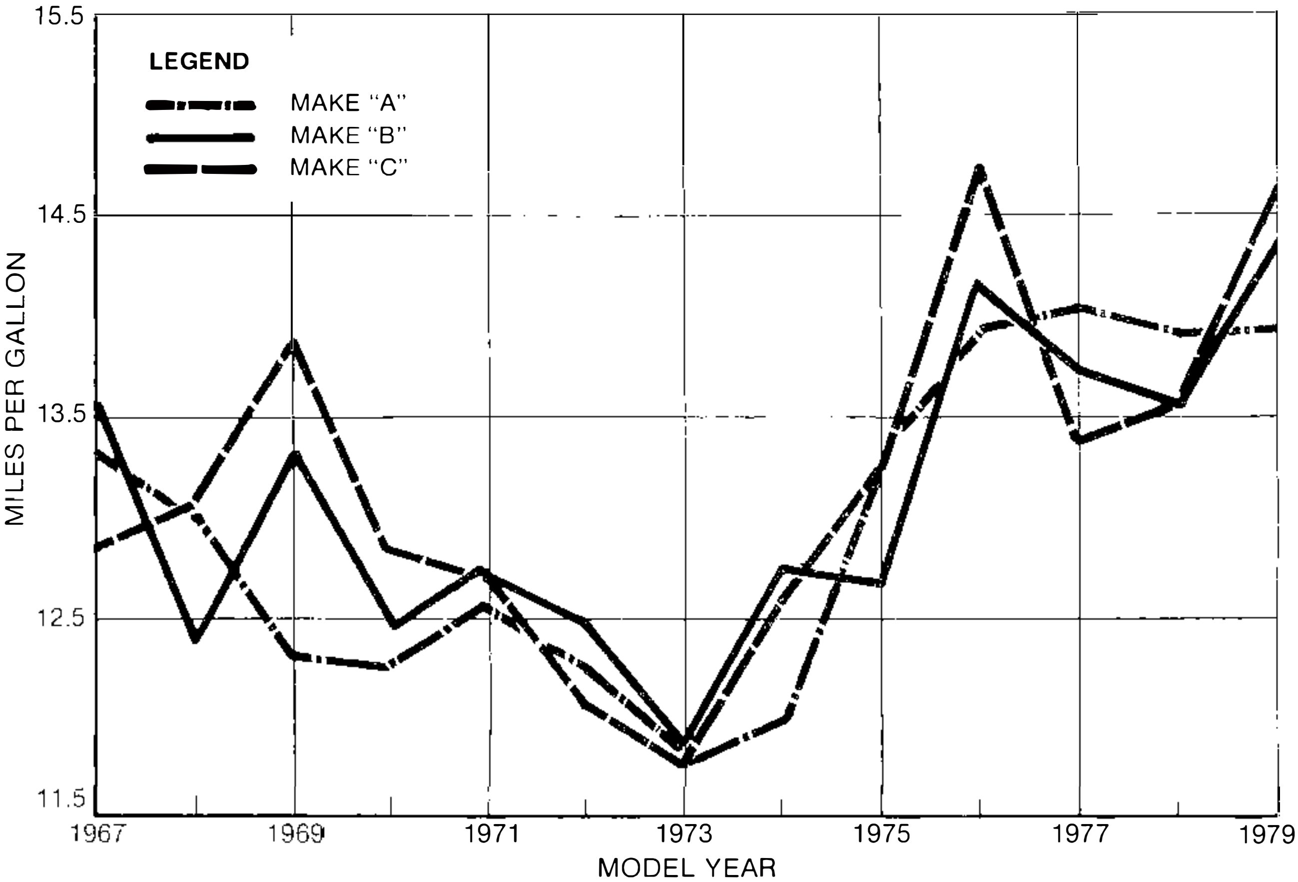

Figure 100. Miles per Gallon vs. Years, All-Fleet Averages—1967-1979.

NOTE: Weight = 4,500 lbs., cubic inch displacement = 350, average monthly miles = 2,000.

SOURCE: American Petroleum Institute, *Fuel Economy Trends in Passenger Car Fleets, 1967-1974,* updated 1982 (in press).

TABLE 69

Ratio of California MPG Level (Commercial Fleets) to Other 49 States' Average -- 1976-1980

Year	Ratio
1976	0.919
1977	0.934
1978	0.935
1979	0.949
1980	1.020

SOURCE: American Petroleum Institute, Fuel Economy Trends in Passenger Car Fleets, 1967-1974, updated 1982 (in press).

Oxygen sensors, like catalysts, are easily spoiled by metallic combustion products. The 1970 and 1977 amendments to the Clean Air Act recognized that fuels and/or fuel additives could conceivably jeopardize public health, and might also jeopardize the integrity of motor vehicle emissions control systems. The 1977 Clean Air Act amendments carried this further and decreed that fuels and fuel additives not "substantially similar" to those used in certification of 1975 and subsequent car models are not permitted in commerce. One such additive, an antiknock substitute for lead known as MMT, has been prohibited after extensive and controversial testing. This judgment was based in part on oxygen sensor effects.

Inspection and maintenance of the delicately balanced systems mentioned above is important to their proper functioning. Due largely to political pressures, states have been reluctant to enforce inspection and maintenance regulations by statute. There is no doubt, however, that properly functioning pollution control equipment can reduce automotive emissions and positively impact the National Ambient Air Quality Standards in some areas.

Ten years ago it was thought that "rolling back" emission levels to very low levels would obviate air pollution. Today it is recognized that some aspects of air pollution control, especially for oxidant precursors, are immensely more complex than originally suspected.

The positive effects that the national motor vehicle emission control effort have yielded are best seen perhaps in the air quality trends for CO.[13] CO is largely generated by transportation, and so should be readily amenable to control by rolling back emissions from transportation sources, especially those from passenger cars. Dramatic reductions in the rates for CO air quality violations for major U.S. cities over the seven-year interval suggest not only that CO will not long remain a pollution abatement problem, but that the present, very stringent, ultimate standards for new vehicles might be relaxed considerably without risking a return to violations in the future, when new environmentally responsive vehicles will have replaced the generally higher polluting ones still in service today.

Natural sources of the photochemical oxidant precursors, hydrocarbons, and NO_x contribute to ozone formation and complicate the problem of developing effective control strategies (see Table 70). Periodic incursion of ozone from the stratosphere further complicates strategy development.

The degree to which automotive emissions should be controlled should be re-evaluated on a cost-effectiveness basis. Enough has been learned in the last decade to support an analysis that considers not only the feasibility of vehicle controls as a means to achieve air quality standards, but the trade-off between energy consumption at the vehicle and at the refinery as well.

Ten years ago, much concern existed over the health implications of lead in gasoline. As a result, EPA named lead a hazardous

TABLE 70

Natural and Man-Made Hydrocarbons
and Nitrogen Oxides in the United States

Source	Hydrocarbons (Millions of Tons Per Year)	Nitrogen Oxides (Millions of Tons Per Year)
Motor Vehicles	11	9
Stationary Sources	11	14
Subtotal (Man-Made)	22	23
Natural Sources	80	23
Total	102	46

SOURCE: Pierrard, John M., "A Common Sense Approach to Automobile Standards," Energy and the Environment, Institute of Environmental Sciences, 1981.

air pollutant and promulgated a phasedown schedule for the use of lead antiknocks. Today, largely as a result of the increased consumption of unleaded gasoline, lead use has been reduced by about 75 percent (see Table 71). The concern for lead emissions has been largely replaced by new concern for so-called "unregulated pollutants," especially diesel particulates. Diesel vehicles emit approximately 60 times the weight of particulates emitted by similar gasoline-powered vehicles. Moreover, they are complex in nature, yield extracts that sometimes exhibit biological activity, and are suspected to be capable of penetration into deep lung tissue. In a declining market for transportation fuels, diesel fuel consumption trends stand out, with steady growth expected over the next 10 years.

The Clean Air Act requires engine manufacturers to support health research on unregulated pollutants, and considerable continued activity is predicted over the next 10 years in the Coordinating Research Council-Air Pollution Research Advisory Committee of the Motor Vehicles Manufacturers Association and the American Petroleum Institute, the new Health Effects Institute, and the EPA. Final answers to the question of unregulated particulate emissions may have to await the results of epidemiological studies.

Over the last 10 years, noise, smoke, and NO_x emissions from aircraft have been reduced as aircraft engines have been retrofitted with improved combustors. The aviation industry foresees no fuel problems as long as the aromaticity of jet fuel can be held below about 25 percent. At the same time, diesel fuels of good low-temperature operability and low-emissions characteristics compete directly with aviation fuels for the same part of the petroleum barrel.

TABLE 71

Gasoline Demand and Lead Use -- 1971-1981

Year	Gasoline Demand* (MB/D)	Unleaded† (Percentage)	Pool§ (Grams of Lead Per Gallon)	Antiknock Fluid (Millions of Pounds Per Year)	Lead (Millions of Pounds Per Year)	Percentage of 1971
1971	6,014	2	2.20	1,135	447	100
1972	6,376	2	2.05	1,125	443	99
1973	6,674	2	1.93	1,104	435	97
1974	6,537	6	1.74	976	384	86
1975	6,675	13	1.60	911	359	80
1976	6,978	20	1.62	973	383	86
1977	7,177	27	1.46	899	354	79
1978	7,412	32	1.32	839	330	74
1979	7,034	37	1.16	700	276	62
1980	6,582	43	0.71	402	158	35
1981†	6,320	49	0.55	300	118	26

*Data from U.S. Energy Information Administration, Petroleum Statement, Annual and December 1980 Issues.

†Data from Ethyl Corporation.

§1971-1979 data from Ethyl Corporation. 1978-1980 data from Director, Field and Support Division, U.S. Environmental Protection Agency.

SOURCE: Memorandum to National Petroleum Refiners Association Board of Directors and Associate Member Representatives, May 1, 1981.

Finally, non-petroleum gasoline blending components, such as alcohols and ethers, which have come into use to meet the increasing octane needs for unleaded gasoline, may be considered to conflict with the "substantially similar" limitation included in the Clean Air Act Amendments of 1977. Several years of experience with a variety of these materials, including the testing undertaken for waiver applications, have resulted in the promulgation of rules that allow most of the benefits to be utilized, while retaining control sufficient to safeguard emission equipment.

B. Marine Mobile Sources

Bunker fuels are heavy petroleum fuels that provide transportation power for the marine sector. They are similar to the heavy fuels used in large facilities for power generation and space heating.

Hypothetically, a marine vessel in port or in coastal waters might be considered a source of air pollution by virtue of its

discharge of stack or (in the case of diesel power) exhaust gases. The subject has been discussed periodically in almost all maritime jurisdictions for many years, but the number of actual restrictions on such operations is small.

For example, the operating permit for the ARCO dock at Long Beach, California, requires that a certain percentage of the vessels burn fuels having no more than 0.5 percent sulfur content by weight while in "adjacent waters" (defined geographically and including waters up to 60 or 70 miles offshore). The city of Valdez, Alaska, in the process of hearings relative to a bond issue for terminal construction, agreed to require the use of bunker fuels containing 0.7 percent sulfur by weight or less during deballasting operations.

Rule No. 1116.1 of the South Coast Air Quality Management District in California restricts vessels operating in harbors and in coastal waters (defined as above) south from the Ventura-Los Angeles County line to the Orange-San Diego County line to the use of fuels having sulfur contents of 0.5 percent by weight or less.

Although such regulations cause inconvenience due to the provision of segregated or even additional fuel tankage, they do not at the present time cause a significant distortion of markets or manufacturing processes. If the imposition of such practices should become widespread, there should be mandatory coordination of such regulations by a national or international group as outlined under the discussions of marine transportation in Chapter Four.

LUBRICANTS

Most lubricants contain additives for various purposes. In the past, some of these additives represented a possible health hazard unless care was taken to observe proper use and disposal practices. A few examples follow:

- Some gear lubricants contained lead, phosphorus, and/or sulfur compounds, primarily to provide extreme pressure characteristics to the lubricant. In some cases they were considered to represent an unacceptable risk to health. Modified formulations or, in some cases, totally new additive formulations were developed.

- Soluble oils, which are oils especially formulated to emulsify readily with 10 to 200 parts of water to each part of oil for use as lubricants and coolants in machining operations, and cutting oils, which are used to lubricate and to protect from corrosion the tools and work pieces in many metal machining operations, have been related to outbreaks of dermatitis in machine shops. These oils presented a disposal problem since used emulsions were frequently disposed of in a public sewer. It was necessary to reformulate many of these compositions in order to minimize the real or perceived health hazard and/or to eliminate any hazard which might be associated with disposal.

- The disposal of used automotive crankcase oil has been a well-publicized environmental concern for many years. The disposition of used oils is discussed in Chapter Four. Most refiners and marketers have faced more than one of these problems in the last decade. Although the solutions were sometimes difficult and consumed great amounts of product development time, the necessary modifications to lubricant formulation or processing did not constitute a major economic impact on either the industry or the public.

ASPHALTS

Asphalts are selected heavy fractions from crude oils. These heavy fractions are further treated with solvents, blowing, and/or heating to incorporate specific properties appropriate to the final intended use. Asphaltic products occupy a unique position in petroleum technology; they have their own processing methods, are described by their own vocabulary, and are defined by their own test methods. They have a large market in road surfacing, roofing manufacture, and special uses such as battery case manufacture and resin board preparation. In 1980, asphalt and road oil accounted for 2.4 percent of total petroleum products consumed, equivalent to about 146 MMB (see Table 58).

The use of these products does not normally impact environmental parameters (assuming proper application and disposal practices) except in the case of the road-surfacing material usually referred to as "cut-back asphalt." As its name implies, this material consists of the heavy, resinous material intended to form, after curing, the permanent road surface, "cut back" with a volatile petroleum solvent that facilitates application and is expected to evaporate during the curing of the road surface. Obviously, the evaporation of this solvent is a source of atmospheric hydrocarbons and, in the usually accepted concept of the formation of atmospheric ozone, could contribute to the atmospheric loading of that oxidant.

Broad restrictions on the use of cut-back asphalt have been included in many State Implementation Plans across the country as part of a hydrocarbon reduction control strategy based on EPA's Control Technique Guidelines. In addition, restriction of the use of cut-back asphalts or the agreement to use, for example, a water emulsion instead of the cut-back asphalt have been devices incorporated in permitting procedures where hydrocarbon offsets were required.

Since paving practices are normally quite variable and individual government units and contractors have different preferences, this bias in the use of cut-back preparations has not significantly distorted manufacturing or distribution practices in the asphalt industry. It cannot, therefore, be positively stated that either the availability or cost of asphalt products has been affected. The restricted use action, however, has resulted in a significant reduction in the use of petroleum solvents in this application.

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[6]Oil & Gas Journal, March 30, 1981.

[7]Adapted from U.S Department of Health, Education, and Welfare, Control Techniques for Carbon Monoxide Emission from Stationary Sources, March 1970.

[8]Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, August 1977; Supplements, May 1978.

[9]U.S. Department of Health, Education, and Welfare, op. cit.

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CHAPTER SIX

FATE AND EFFECTS OF SPILLS

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FATE AND EFFECTS OF SPILLS

INTRODUCTION

Oil spills, large and small, have long been of concern. In addition, hazardous substance spills have recently received considerable attention, primarily outside of the petroleum industry. Oil and hazardous substance spills attributable to the petroleum industry can be derived from both land- and marine-based activities of all the segments of the industry operations: exploration and production; refining; and storage, transportation, and marketing.

Great attention has been focused on actual oil spills and potential spill sources. Within the petroleum industry, hazardous substance spills are less frequent, smaller, less spectacular, and have much more localized environmental impact than do oil spills.

Prevention of spills is the first line of defense in protecting life, property, and the environment. Effective prevention plans can reduce spill incidents. Experience has shown that equipment failures and operational or human errors are the principal causes of spills. Equipment failures can be minimized through good design and engineering, proper maintenance, and frequent inspection. Operational errors can be reduced by personnel training, including an awareness of spill prevention, and adequate supervision of procedures.

Spill prevention is not 100 percent effective, however, and some spills do occur. Spill contingency plans have been developed to respond to this eventuality and a variety of spill control and cleanup techniques have been developed. In addition, there has been a substantial increase in the knowledge of the fate and effects of spilled materials.

I. Legislation and Regulations

Section 311 of the Clean Water Act and its regulations deal specifically with oil and hazardous substance spills in U.S. waters. The Act was drafted to encourage a high standard of care in the handling of oil and hazardous substances and prohibits the discharge of oil or hazardous substances in quantities that may be harmful. The Act requires that spills be reported, and that civil penalties be assessed accordingly. Failure to report a spill can subject a discharger to criminal penalties. Plans for the prevention of oil and hazardous substance spills are also required by the Act.

Other legislation that addresses the problem of spills, particularly those of hazardous materials, is the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) (Superfund). A detailed discussion of CERCLA is contained in Chapter One of this report.

HAZARDOUS SUBSTANCE SPILLS

The petroleum industry is a very small source of hazardous substance spills. The quantities of hazardous substances used within the industry are small relative to the volumes of oil handled. While the impacts of hazardous substance spills can be serious (e.g., fish kills), in most cases they are temporary and do not pose long-term problems.

Hazardous substances are those materials designated by EPA under Section 311 of the Clean Water Act.[1] As of October 1981, the list of hazardous substances contains 298 materials, chemicals, and compounds.[2] Spills of hazardous substances must be reported promptly to the National Response Center if the quantity spilled exceeds the reportable quantity specified in the regulations.[3] EPA is currently in the process of redefining reportable quantities for spills of hazardous substances under CERCLA. These materials are used in refineries as process water and wastewater treatment chemicals, lube process solvents, and additives, and are manufactured as a component of some products (primarily gasoline). Some of the more common hazardous substances used in refineries and their reportable quantities are shown in Table 72.

These materials are handled with care within the refineries and when spills occur they are typically contained within tank dikes, neutralized, or removed during wastewater treating operations. The spill prevention activities within refineries to control oil spills (Spill Prevention, Control and Countermeasure Plans) also serve to control hazardous substance releases. As a result, actual reportable or harmful releases to navigable waters are minimized.

The primary focus of hazardous substance spill control is prevention, because spill cleanup actions are very difficult in most cases, and impossible in others. These cleanup difficulties arise because of the diverse nature of the materials on the hazardous substance list used in refineries; e.g., some are completely water soluble (sodium hydroxide) while others are relatively insoluble (toluene).

I. Hazardous Substance Spill Data

As a result of the reporting requirements of the Clean Water Act, the U.S. Coast Guard maintains extensive data on reported spills of hazardous substances. The data on hazardous substance spills show the trends illustrated in Figure 101.

Hazardous substance spill data for 1980 show that liquid spills from all sources in the entire United States totaled 625,465 gallons (see Table 73). Of this total, 72 percent was from nontransportation sources, 10 percent from marine facilities, 7 percent from pipelines, 6 percent from vessels, 3 percent from land vehicles, and 2 percent unknown. Dry bulk spill data for 1980 show the entire U.S. amount to be 1,230,418 pounds. Of this total, 95 percent was from pipelines, 2 percent from vessels, 2 percent from nontransportation sources, and 0.2 percent from land vehicles.[4]

TABLE 72

Hazardous Substances
Common in the Refining Industry

Substance	Reportable Quantity (Pounds)
Ammonia	100
Benzene	1,000
Chlorine	10
Furfural	1,000
Hydrofluoric Acid	5,000
Hydrogen Sulfide	100
Phenol	1,000
Sodium Hydroxide	1,000
Sulfuric Acid	1,000
Tetraethyl Lead	100
Toluene	1,000
Xylene	1,000

SOURCE: Determination of Reportable Quantities for Hazardous Substances, Code of Federal Regulations, 40 CFR 117.

The 1980 data show that petroleum refineries contributed only 5 percent of the liquid spilled and 0.2 percent of the dry bulk materials spilled. No hazardous substance spills were reported for other petroleum industry operations.[5]

OIL SPILLS

Oil spills are probably the most visible and well recognized of all accidental industrial releases. During the last decade, substantial work has been done to prevent oil spills, clean them up when they occur, and study the overall impact of all oil inputs into the world's waters. The remainder of this chapter discusses these efforts, and their results.

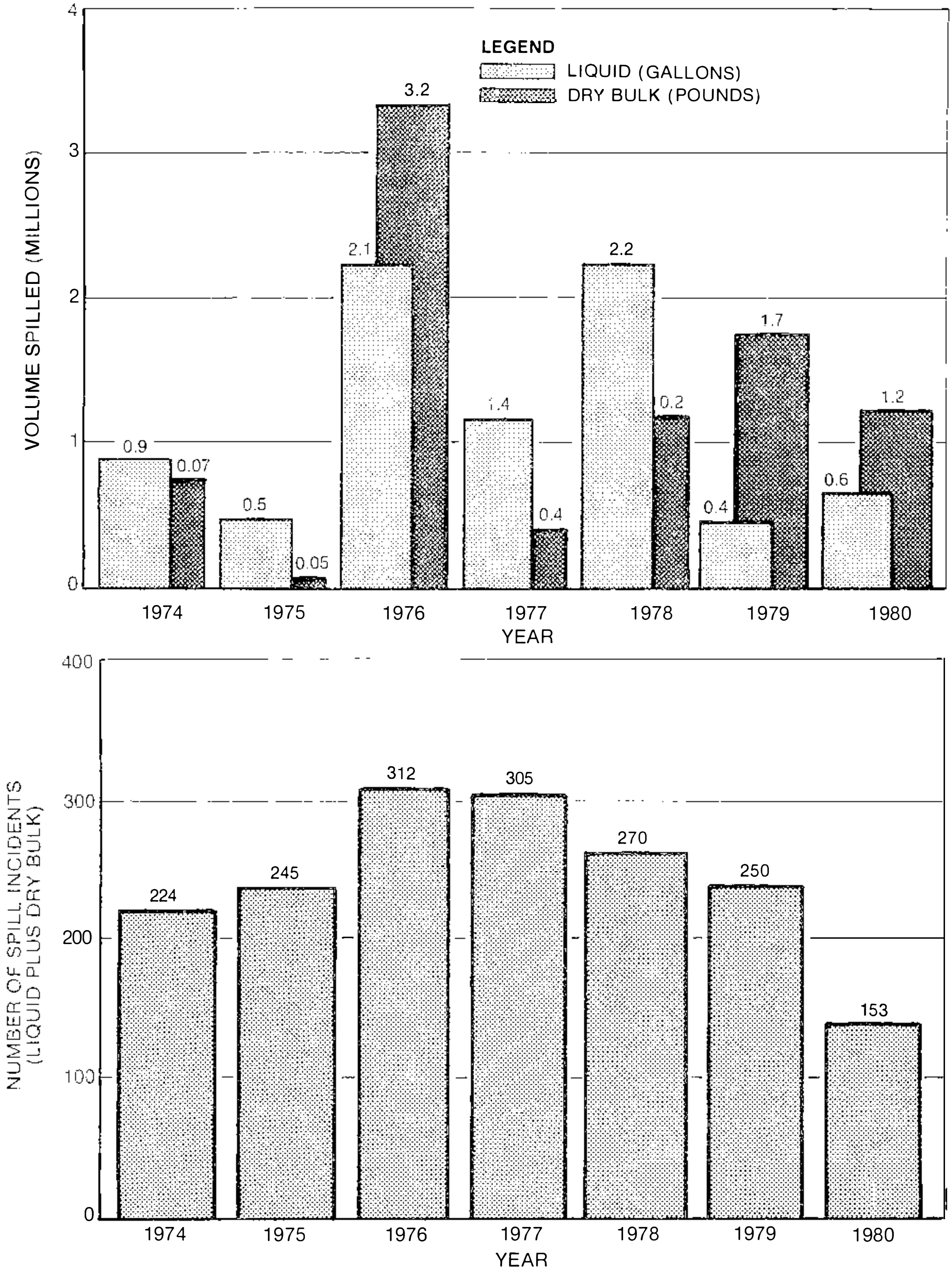

Figure 101. Hazardous Substance Spill Trends—1974-1980.

SOURCE: Department of Transportation, U.S. Coast Guard, *Polluting Incidents In and Around U.S. Waters*, Calendar Years 1979 and 1980.

TABLE 73

Spills of Oil and Other Substances -- 1980

Spill Size (Gallons)	Oil Number*		Oil Volume (Gallons)	%	Hazardous Number*		Hazardous Volume (Gallons)		Number*		Volume (Gallons)		Number*		(Gallons)	
1 - 9	2,226		6,232	0.1	20	1 .	74			9.6	400	0.2	2,401	25.1		
10 - 49	1,845	23.5	40,884	0.6	20	15.0	447			5.3	1,653	.	1,950	20.4		
50 - 99	587	7.5	38,409	0.5	4	3.0	240	0.0	32	2.0	2,178	0.8	623	6.5	40,827	
100 - 499	874	11.2	179,481	2.4	20	15.0	3,411	0.5		2.8	9,425	3.6	939	9.8	192,317	
500 - 999	197	2.5	128,768	1.8					10	0.6	6,200		211	2.2	137,368	
1,000 -	182	2.3		3.7				1.7		0.7		7.2		2.1		
,	79			3.8		11.3					27,900	10.7		1.1		
5,000 - 9,000	49		341,220	4.7	3			3.7		0.3	38,400	14.7				
10,000 - 49,999	45			13.6							105,600					
				12.1	--		--	--	1							
	12			38.5					--	--	--	--	13			
				18.3	--	--	--	--	--	--	--	--	1			
	773	9.8	--	--			--	--		56.3	--	--	1,711		--	
	954	12.2	--	--	1		--	--		21.5	--	--		13.6	--	
	7,837	100.0		100.0												

*Number of spills reported.

I. Oil Spill Data

The Clean Water Act and its implementing regulations prohibit the discharge of oil. Spills that produce a sheen or cause a sludge or emulsion deposit must be reported to the National Response Center. As a result of this reporting requirement, the U.S. Coast Guard maintains extensive data on reported oil spills. The data on oil spills show the trends illustrated in Figure 102.

Detailed Coast Guard data show that in and around U.S. waters in 1980 there were 7,837 oil spills, totaling over 7.3 million gallons (see Table 73). Of this total, 45 percent was from vessels, 23 percent from pipelines, 12 percent from nontransportation sources, 11 percent from marine facilities, 6 percent unknown, 2 percent from land vehicles, and 1 percent from land facilities.[6]

The Coast Guard data reveal that though numerous small oil spills occur from a variety of sources, large oil spills (those over 100,000 gallons) are very rare. Small spills occurring at industrial facilities are usually contained and removed by facility personnel using available materials while larger spills may require the services of a cleanup contractor or a spill cooperative. Spills of over 100,000 gallons, depending on location, may require a coordinated response effort of numerous companies, cooperatives, contractors, and government agencies.

U.S. Coast Guard data for 1980 (see Table 73) reveal that over 70 percent of reported spills were under 500 gallons, 7 percent were more than 500 but less than 50,000 gallons, and less than 0.35 percent were more than 50,000 gallons. About 22 percent of spills reported were described as of unknown quantity or as an oil sheen.

OIL SPILL CONTROL MEASURES

The goals of oil spill control are both ecological and economic. The primary ecological goal is the protection of the ecology of the land/water area against permanent harm. The economic goals are protection of beaches, shorelines, and associated structures against damage, and the recovery, if possible, of a valuable natural resource -- petroleum. To accomplish this task, around-the-clock capability to respond to spill incidents must exist.

I. Containment and Recovery

Oil spills may be contained and often recovered either by purely mechanical methods or by absorption of the oil and subsequent removal. New methods of oil spill containment and recovery continue to be developed as industry seeks better ways to clean up oil spills.

Next to prevention, the most important procedure for mitigating ecological and economic loss from spilled oil is mechanical containment and recovery. This includes the use of containment booms,

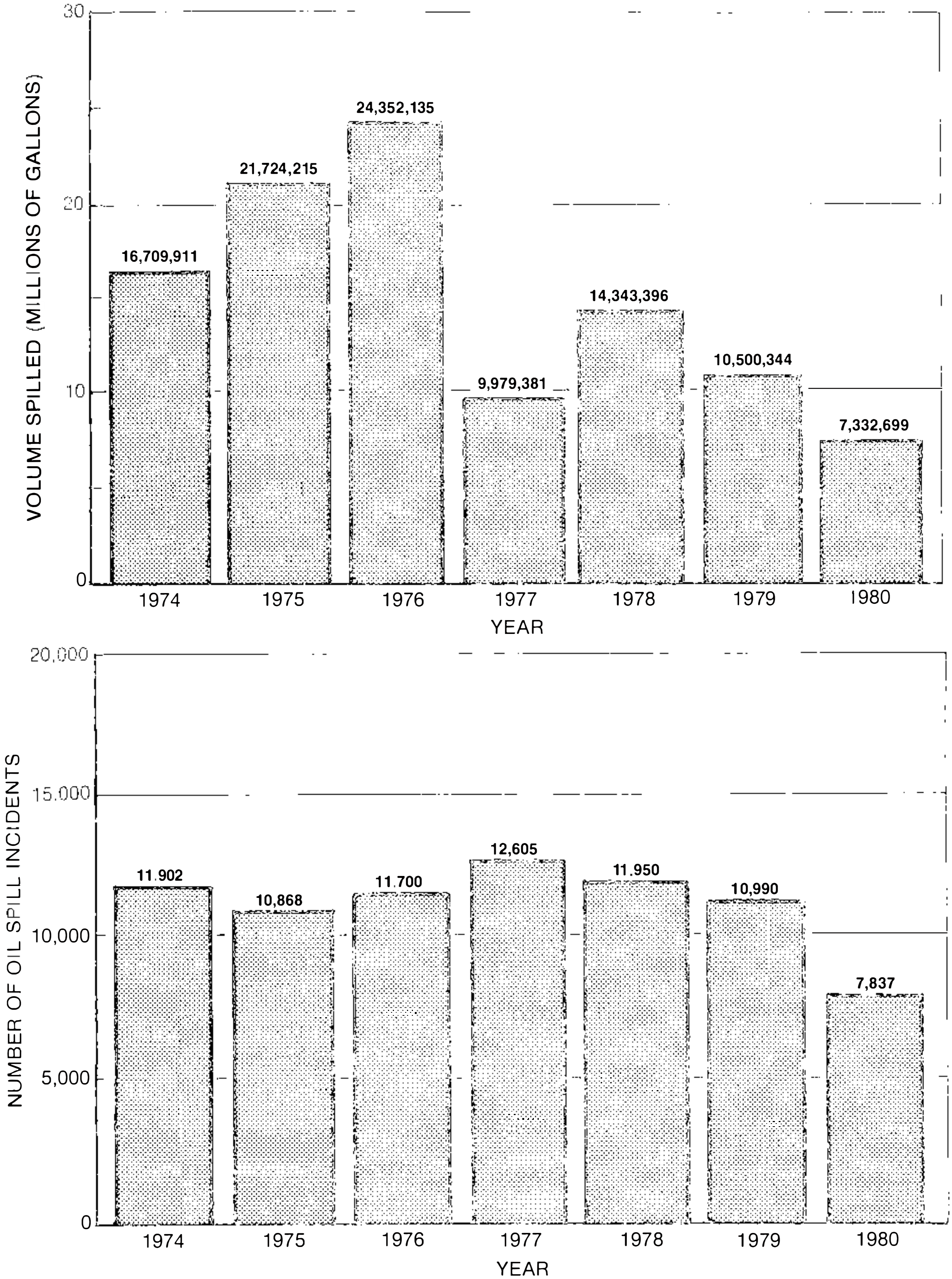

Figure 102. Oil Spill Trends—1974-1980.

SOURCE: Department of Transportation, U.S. Coast Guard, *Polluting Incidents In and Around U.S. Waters*, Calendar Years 1979 and 1980

oil skimmers, sorbenting, and other devices. Equipment and procedures for containing and recovering oil spills in protected waters are well developed. In addition, some of these devices are effective in open waters under mild conditions. However, the containment of oil in the open sea under extremely adverse conditions is nearly impossible, regardless of equipment design.

A. Booms

Spilled oil can be contained by floating booms consisting of a float system from which a skirt hangs downward into the water. Sections of boom can be strung together to form a barrier of the desired length. Oil is prevented from being carried under the boom by the skirt, which is weighted to keep the boom skirt upright. Booms are used to contain or direct oil by a variety of means including encirclement, sweeping oil to a collection point, and/or directing oil by forming a barrier along which the slick moves to a collection point.

Booms are highly effective for containing oil in harbors, inland waters, and under calm to moderate conditions in the open sea. Sweeping speeds must be very slow when booms are used in the open sea. Booms can be used effectively in directing oil slicks to a given point, provided there is a proper angle between the boom and current direction, preferably so that the current normal to the boom is less than one knot.

The usual reason for failure of booms is that, as oil accumulates, it is carried under the boom by the rapid currents. Lengthening of the skirts requires increasing the strength of the boom in order to overcome the hydraulic forces. Also, there is a point where increased boom draft provides no additional advantage to restrict entrainment.

In addition to the containment problem, open-sea tending and anchoring of booms are difficult. Forces built up by wind and wave action drag anchors and break lines and anchor fittings. Articulated booms are necessary to conform to the surface of the sea.

Air barriers have been used in harbors at oil tanker terminals. An air barrier consists of a pipe or hose positioned several feet below the water surface, in some cases on the bottom, from which air is jetted through nozzles along the length of pipe. The upwelling air/water current produced by the stream of air creates a flow on the water surface, which tends to repel floating oil. To be successful, the air barriers must be tailored for each installation; they are not applicable in offshore operations because of the variable conditions and forces that occur.

B. Skimmers[7]

After spilled oil has been contained, it must be removed. A skimmer provides one of the least expensive and most effective means of removal with the advantage of recovering oil without changing its physical or chemical properties. Although many

skimmer units are commercially available, there are five basic types:

- Floating Suction Units. Floating suction units are constructed to float at the oil/water interface. A self-priming pump is normally used to draw skimmed oil off through attached floating hoses. The skimming head is flexible, conforms to wave action, and will skim oil in spite of small waves.

- Floating Weir Skimmers. Floating weir skimmers are designed to allow oil to flow over the top edge of a weir and into a collecting vessel where the oil is pumped away through a flexible hose. The skimmer performs effectively in quiet waters.

  A recent development has been the manufacture of a skimming boom. This device is a combination of a spill containment boom and a floating weir skimmer. The boom is slotted to skim contained oil. When sufficient oil is collected, it flows through a section of the boom to a pump and then into separation/collection facilities. When the oil layer becomes minimal, pumping stops. This process reduces the volume of water handled and significantly increases the effectiveness of the skimmer.

- Oleophilic Disks, Drums, or Belts. All oleophilic skimmers work on the principles of absorption, adsorption, or adherence. The oleophilic material continually passes through an oil slick and the oil adheres to or soaks into the material. The sorbent material is drawn from the water, the oil is wiped or squeezed from it, and the sorbent material passes through the slick again to collect more oil. Recovered oil is pumped to a holding vessel or tank.

- Hydrodynamic Inclined Plane. This skimmer consists of an inverted endless belt designed to carry the oil beneath the surface as the skimmer is maneuvered into the oil. The oil will leave the belt at the bottom and float upward into a collection well to be pumped away to recovery.

- Induced Vortex or Cyclone Skimmer. This type of skimmer employs the centrifugal force of a vortex to separate oil and water. Oil accumulates near the top of the vortex and is pumped to storage tanks while water is expelled through an exit port. A vortex can be created either by a spinning disc, or by the forward speed of a vessel.

Suction units and floating weirs are the most common types of skimmers because they are usually simple to operate, versatile, and generally cost less than other types. Most small skimmers can be compatible with each other, providing proper hose connections and couplings are available. Small skimmers are relatively inexpensive and can be used on small and large spills. Large self-propelled skimmers are very costly and are usually purchased by cooperatives and governments.

C. Sorbents

Sorbent materials pick up oil by two mechanisms -- absorption (blotting or soaking) or adsorption (surface adhesion). The use of sorbents is not cost-effective for cleaning up large spills; however, they can be a useful complement for specialized tasks such as picking up oil in difficult places and sealing booms.

D. Other Methods

A unique system for containment of ocean-floor seeps has been used with limited success. Underwater hoods or tents have been installed on the ocean floor to collect the seep oil and carry it through flexible piping to a suitable container or structure on the ocean surface. The tent center is held aloft off the ocean bottom with buoys, allowing the oil/gas mixture to migrate toward the tent apex to which the transfer hose is connected. The tent is securely lashed to a frame slightly larger than the tent's base dimension. The frame is made from piping, suitably valved for water flooding or air displacement, and hence serves both as anchor or flotation system, as needed.

Several new developments in spill containment and recovery appear encouraging. Oil emulsions, known as "chocolate mousse," are very viscous and difficult to pump after they are collected by a skimmer. A new procedure to inject emulsion-breaking chemicals at the pump significantly decreases the emulsion's viscosity, making for easier pumping and skimming, and enhanced downstream oil and water separation. A second and more recent development is a chemical treatment process designed to partially solidify spilled crude oil, so that it can be picked up like a rubber mat.

II. Treatment

While containment and recovery of spilled oil provides the most positive control, the employment of such measures is not always possible. Nature itself has enormous capacity for disposing of hydrocarbons, and man can hasten the process.

It is well known that many microorganisms in both saline and fresh waters have the capacity to degrade hydrocarbons by using them as food. In many circumstances, the best treatment of an oil spill would be the natural dispersion by winds, waves, and currents, and subsequent microbial degradation. Due to the necessity to protect resources from immediate damages, this natural treatment frequently cannot be used except when prevailing winds and currents carry the oil away from shorelines and areas of habitation, recreation, and commerce. As a result, a variety of treatment methods have been developed. Two of the most effective methods, dispersants and combustion, are discussed below.

A. Dispersants

Many of the potentially adverse effects of spilled oil can be alleviated or minimized by the use of chemical dispersants. Breaking the oil into small droplets that disperse into the water accelerates the weathering of toxic constitutents and otherwise alters

the properties of the oil. In addition, the movement of an oil slick by the wind is stopped by dispersing.

Chemical dispersants have been widely used worldwide to control oil spills, but to date have been used only sparingly in the United States, largely because of their adverse effects noted during the *Torrey Canyon* oil spill. Damage during that spill was caused by improper use of highly toxic industrial cleaners.[8,9] Newer dispersants have very low toxicity, and methods of application are now more effective.[10-13]

Present U.S. policy mandates that prior acceptance by the Environmental Protection Agency (EPA) of dispersant data is required before use except when, in the judgment of the On-Scene Coordinator (OSC), the hazard to human life or of fire is so imminent that the time delay for obtaining an accepted dispersant would be excessive. Because there are now 18 products on the EPA data-accepted list, it is unlikely that even under hazardous conditions the OSC would use a dispersant not on that list. Approval for use is granted on a case-by-case basis. Use of dispersants for other than hazardous conditions must have the concurrence of the EPA representative or alternate representative on the Regional Response Team (RRT). Even then, they are to be used only when the EPA representative determines that the least overall environmental impact will result from their use,[14] and records of uses and effects must be kept. EPA and state agencies are now taking a more positive attitude towards dispersants than previously. Since there are a large number of effective products now available and methods of application are proven, the use of such dispersants has become one of the more versatile and serviceable spill-control methods, and is likely to increase in the future.

Dispersants have been used routinely in U.K. oil ports and other areas for the rapid treatment of small floating slicks. For example, they have been used in Milford Haven since its inception as an oil port. These treatments help reduce the oiling of amenity beaches, other shorelines, and boats and other structures. At certain times of the year they have helped minimize bird casualties. There is no evidence that these uses cause adverse biological effects.

There is a consensus that dispersants can be used in offshore or deep waters, but should not be used in shallow waters or on land. The reasoning behind this is that the dispersant/oil mixture would not be diluted quickly enough in shallow water to prevent damage (e.g., to shellfish beds). Also, dispersed oil might penetrate more easily into sediments. These assumptions have never been fully tested in field experiments. However, experiments to compare chemically dispersed oil with untreated oil were recently conducted (although the results have not yet been released) in the Canadian Arctic[15] and in a Maine cove. These projects were designed to use dispersed oil concentrations similar to those found under actual research test spills.[16] Both tests will determine whether dispersed oil used in shallow inlets with sand or mud bottoms are ultimately more damaging than leaving the oil alone, and

will measure the toxicities of oil to intertidal and subtidal organisms. Also, a series of littoral and sublittoral field experiments have been initiated in the United Kingdom and preliminary results have been reported.[17]

The dispersants presently available may be broadly classified as water based or organic solvent based. As a general rule, the latter are effective over a wider range of conditions and petroleum products, but tend to be more toxic and exhibit lower flash-points. Thus they require somewhat greater care in handling and application than their water-based counterparts, and are rarely used today.

Dispersants generally are applied by spraying from vessels or aircraft, in concentrations ranging from 1:5 to 1:50 (dispersant: oil). If the chemicals are properly applied, the resulting benefits include a rapid dilution and downward mixing of the oil, reduction in adhesion, and accelerated weathering.

1. Movement and Dilution of Dispersed Oil

An important advantage of dispersion is rapid dilution and downward mixing in near-surface waters.[18,19] This removes the oil from most of the wind's influence so it does not travel as far or as quickly as surface slicks. During a Gulf of Mexico well blowout, chemical dispersants were sprayed on the platform and surrounding water.[20] The dispersed oil plume was observable only 1 to 1.5 miles from the spill site, whereas untreated surface slicks extended six to nine miles on most days and as far as 50 miles on two occasions. Oil that does not travel far is less likely to strand on beaches, impact avian species, or interfere with commercial and sport fishing.

2. Reduction of Oil Adhesion

Normally, oils adhere to almost all solid surfaces. Dispersed oil droplets do not stick to each other, however, nor to most solid surfaces. This includes suspended mineral particles,[21] thereby decreasing the amount of oil that sinks. This mechanism can be particularly effective when dispersed oil encounters turbid water, such as from some rivers. Without emulsification the oil could be carried downward in the water column by sediment particles and concentrate in sediments beneath the zone of mixing.[22]

Chemically dispersed oil from a near-shore spill, should it enter the intertidal zone, should have less tendency than untreated oil to adhere to sand, rocks, and marine plants and animals. This would minimize the smothering of intertidal marine life that has occurred with nondispersed, partly weathered crude oil and viscous bunker C oil.

Reduced adhesion should also lessen the adverse effects of oil on sea birds if they encounter it as an emulsion plume. Further, the smaller aereal extent of an emulsion plume compared with that of the same oil as a slick should lessen the opportunity for birds to be oiled.

3. Acceleration of Weathering and Biodegradation

The formation of small oil droplets results in a large surface-to-volume ratio, accelerating evaporation, solution, and biodegradation. These small droplets lose volatile hydrocarbons more rapidly than some slicks, thereby reducing the toxicity of oil that organisms may come into contact with or ingest.

Concentrations of chemically dispersed oil in offshore waters are typically from 1 to 60 ppm, and in a few hours' time, dilute to near-background concentrations.[23] These are lower than amounts observed to cause adverse biological effects in laboratory bioassays.

The increased surface area also aids bacterial biodegradation, which occurs at the oil/water interface.[24] The movement of emulsion droplets through the water also makes oxygen and nutrients more readily available to microorganisms. This accelerated weathering quickly reduces the toxicity of oil in the dispersed droplets.[25,26]

B. Combustion

Destroying oil slicks by combustion has been attempted with little reported success. In some cases, ignition in the early periods of an oil spill is not desirable because of danger to both personnel and property. After weathering on the ocean surface, crude oil volatile fractions are lost and the slick is thinned, making ignition and continuous burning difficult, if not impossible. To continue burning, enough heat must be generated to keep the oil at its ignition temperature.

In order to burn an oil slick deficient in volatiles and too thin to maintain combustion, the use of a wicking material containing a combustion promoter has been suggested. There have been reported successes of some such devices, but none on a large-scale spill. The possibility of sustaining burning to completion by wick action of materials spread on a sea slick should not be overlooked, but the very definite dangers and uncertainties must be carefully evaluated before such a process is attempted on a major spill.

If conditions and circumstances allow it, the burning of oil still contained in a stricken vessel can be very effective in reducing the amount of oil spilled in the sea.

CONTINGENCY PLANNING FOR RESPONSE TO OIL SPILLS

The purpose of a contingency plan is to provide direction and information for handling oil spills when they occur at a facility. The essential contingency elements of effective oil spill cleanup include: a flexible, detailed, and preconceived plan for action to clean up the oil; an organization consisting of personnel, equipment, and supplies to implement the plan; and a notification system to activate the plan when an oil spill occurs.

Within the petroleum industry, contingency planning for response to oil spills has reached an advanced state due to the interest of the industry itself as well as impetus supplied by the various federal, state, and local regulatory bodies with related interests. Each oil company has specific contingency plans for its facilities which have a potential to discharge to the environment. Each plan should include notification and alerting procedures, reporting requirements, plant layout and operations, equipment inventories, waste disposal plans, training procedures, and a spill response team organization that delegates coordination, equipment management, damage assessment, communications, public relations, and environmental mitigation responsibilities to specific individuals.

Training, orientation, and motivation of personnel are important for effective implementation of a contingency plan. The supervisory personnel implementing the plan must be trained to effectively evaluate the changing situation at the cleanup scene and make the best decisions to direct the cleanup operation.

It is important that a spill contingency plan and organization recognize how the plan fits into the National Response Mechanism. The federal spill response mechanism in the United States is designed to discover spills through surveillance, provide for timely notification of all those charged with responsibilities to evaluate the situation, initiate immediate containment actions and countermeasures, and provide for cleanup, mitigation, and disposal should the discharger be unknown or be inadequate to the task.

In place and operative are the National Contingency Plan, two international contingency plans (one with Canada and one with Mexico), regional and local contingency plans, a cadre of predesignated OSCs from EPA and the U.S. Coast Guard, a National Response Team (NRT), and RRTs to provide advice and assistance to the OSC. The National Contingency Plan is being updated and a revised version should be available in 1982.

The National Contingency Plan "provides for a pattern of coordinated and integrated responses by Departments and Agencies of the Federal Government to protect the environment from the damaging effects of pollution discharges." In the United States, the Coast Guard is charged with providing the pre-designated OSC in coastal regions and EPA has that responsibility in inland regions. The OSC has complete federal responsibility for on-scene actions to prevent, contain, assure cleanup of, or otherwise mitigate spills of oil that affect, or threaten to affect, U.S. waters. Regional contingency plans delineate the exact boundaries of each OSC so there is absolutely no question about who has the federal responsibility in these matters. The OSCs maintain libraries of publications for reference, a group of well-trained personnel to respond to spills or threats of spills, and subregional plans, with inventories of critical water-use areas, drinking water intakes, potential pollution sources, known environmentally sensitive areas, scientific communities, local contact points, and cleanup contractors and equipment. Other components of the plan are listed in Table 74.

TABLE 74

Components of the National Contingency Plan

Regional Response Team	Conduct pre-planning, prepare Regional Contingency Plans and provide the federal OSC with advice and assistance during a pollution incident or threat of pollution.
National Response Team	Perform functions of RRT at national level; coordinate national and international contingency plans; provide large scale resources.
National Strike Force	Provide communications support, advice, containment, cleanup, mitigation assistance, and knowledge and expertise in ship salvage, damage control, diving, and removal techniques.
Environmental Response Team	Advise the OSC on environmental issues related to spill containment, dispersant application, cleanup, and damage assessment.
Scientific Support Coordinator and team (EPA or NOAA)	Provide scientific assistance including oceanography, chemistry, location of environmentally sensitive areas, assessment of environmental damage, and coordination of on-scene scientific activity.

I. Oil Spill Cooperatives[27]

Oil spill cooperatives are entities formed by two or more companies for the purpose of providing a standby pool of mutually owned equipment and/or manpower to combat oil spills. Cooperatives are not always chartered, staffed, or operated the same way throughout the country. Rather, they are tailored to fit the needs of the members. The operations of a cooperative include keeping equipment and training current and, in some cases, supervising member companies' employees when engaged in cleanup operations. Periodic drills are necessary to assure that the cooperative can be activated effectively. There are more than 90 well-recognized oil spill co-ops serving the 50 states (Figure 103).

QUANTIFICATION OF OIL IN THE ENVIRONMENT

I. Sources

For millions of years petroleum has been a natural component in the environment. Marine oil seeps are quite common throughout the world, as are seeps on land. Throughout recent geological time,

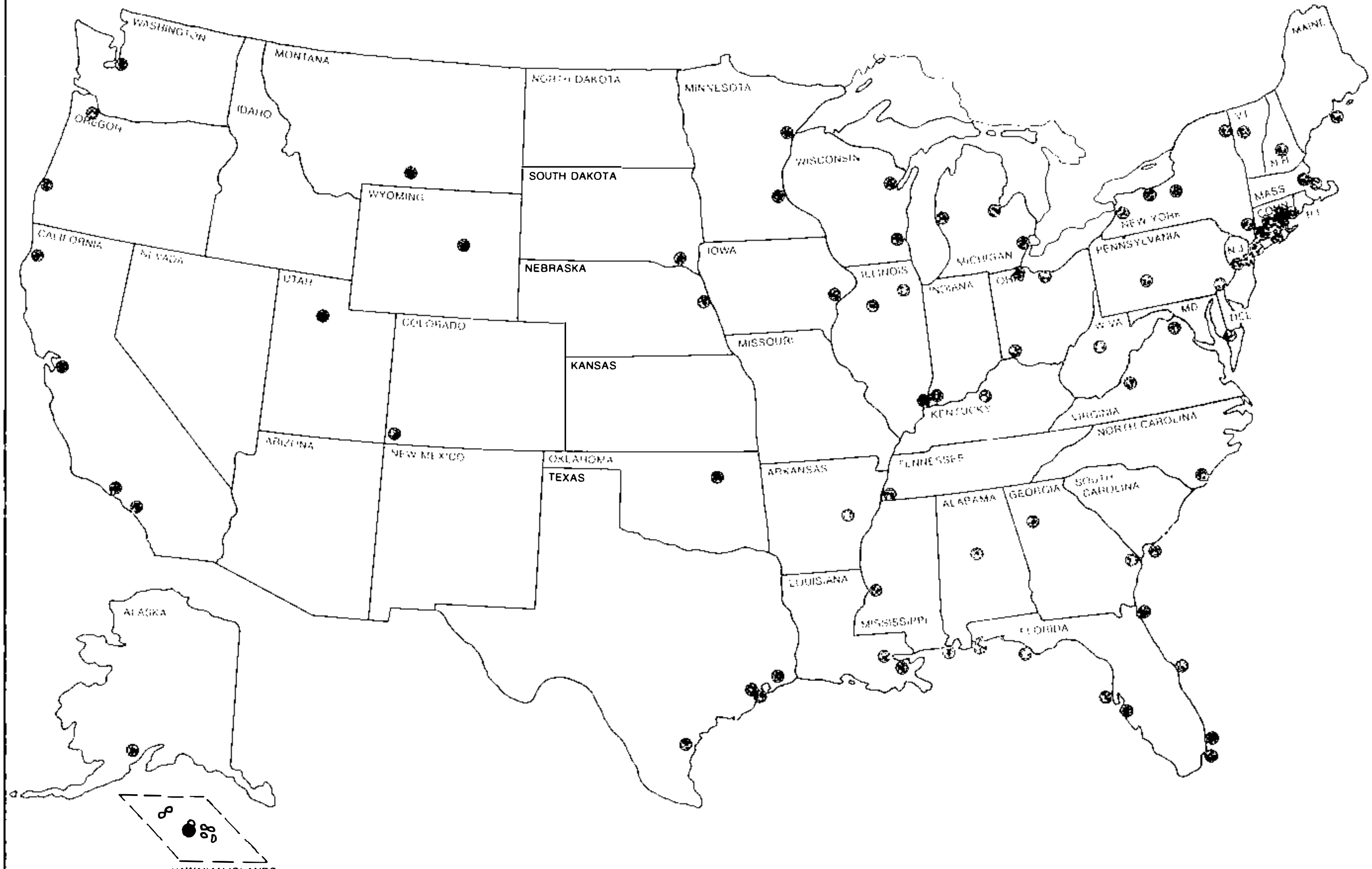

Figure 103. Locations of U.S. Oil Spill Cooperatives.

SOURCE: American Petroleum Institute, *Oil Spill Co-op Directory*, April 1980.

erosion of uplifted sediments and breached petroleum reservoirs have contributed hydrocarbons continuously to the environment. Probably larger amounts have been added by plants and animals. Since the discovery of petroleum and its increased transportation and usage, man has contributed increasing amounts of petroleum to the environment. Natural processes destroy at least the major portions of hydrocarbons contributed from the various sources. If this were not so, the seas would be covered with a layer of oil.

The U.S. National Academy of Sciences (NAS), in a landmark study on petroleum pollution published in 1975, estimated that about 6 million metric tons per year of petroleum entered the world's oceans.[28] This amount is based on careful estimates of the input of petroleum into the oceans from various sources, as shown in Table 75. There is a lack of reliable data for some of these estimates. However, even for those estimates based on adequate data, annual data can vary greatly from the averages shown in Table 75. The NAS recently commissioned a study to update the 1975 report, drawing upon the substantial amount of new information and experience gained since that time; the study is expected to be published in 1983.

Of the approximately 6 million metric tons of petroleum entering the oceans each year, over 40 percent is in runoff from cities, rivers, and coastal facilities. About one-third arises from normal tanker operations and other transportation activities. Tanker and nontanker accidents contribute about 5 percent. Offshore production (including spills) contributes 1 percent, and natural seepage and atmospheric fallout each contribute 10 percent. Details on each of these sources and some of the perturbations follow.

A. Urban Runoff

The NAS estimate of 0.3 million metric tons per annum (MTA) from urban storm drainage was based upon analysis of waters from southern California;[29,30] waters from urban areas around Jamaica Bay, New York;[31] and results from Stockholm, Sweden.[32]

In the 1973 southern California estimates, petroleum was assumed to constitute 75 percent of the hydrocarbons in urban runoff. A 1981 study of the extractable organic matter in urban storm water runoff in the Los Angeles basin substantiates the 1975 NAS estimate.[33] This study found that the Los Angeles River, which drains only 20 percent of Los Angeles County, contributed about 1 percent of the annual world petroleum hydrocarbon input to the ocean via urban runoff. Hydrocarbons constituted approximately 60 percent of the total solvent-extractable organics in Los Angeles River storm waters. About 95 percent of these hydrocarbons were associated with particulate matter and were primarily derived from petroleum residues.

Among the probable sources of hydrocarbons in the Los Angeles River basin are vehicular exhaust particles; discarded lubricating oils; atmospheric fallout (rain and dry; e.g., forest fires, combustion of fossil fuels, and transport of bio-organics by the

TABLE 75

Sources of Petroleum Entering the Oceans*

	Millions of MTA†	Percentage of Total	
Urban Runoff	0.3	5	
River Runoff	1.6	26	44
Coastal Facilities (e.g., sewage plants, refineries)	0.8	13	
Transportation			
Load-On-Top (LOT) Procedures	0.31	5	
Non-LOT Procedures	0.77	13	
Dry Docking	0.25	4	30
Terminal Operations	0.003	0.2	
Bilges and Bunkering	0.5	8	
Tanker Accidents	0.2	3	
Nontanker Accidents	0.1	2	
Offshore Production	0.08	1	
Natural Seepage	0.6	10	
Atmospheric Fallout	0.6	10	
	6.113	100	

*Source of data: National Academy of Sciences, Petroleum in the Marine Environment, 1975; based on 1973 estimates. Updated estimates are expected to be published by the National Academy of Sciences in 1983.

†MTA = metric tons per annum.

winds); spillage of crude oil and refined petroleum products during production, processing, and transportation; leached or eroded pavement; natural biogenic sources on land; and erosion of organic-bearing sedimentary rocks.

B. River Runoff

Input from rivers, estimated to be the largest single source of petroleum hydrocarbons, is poorly documented. The NAS estimate of

1.6 MTA was determined from sediments discharged from the Mississippi River and in San Francisco Bay. The Mississippi was taken as representative of all U.S. rivers, and its mean sediment load was used to calculate the total hydrocarbon discharge for the United States. This estimate was then multiplied by three, the ratio of world to U.S. petroleum utilization, to obtain the estimate of world input from rivers.

C. Coastal Facilities

In 1973, coastal refineries were estimated to contribute 0.2 MTA. This amount should be shrinking, particularly in the United States, due to trends toward recycling of cooling water, increased air cooling, and more efficient oil removal from effluents.

Coastal municipal wastes (sewage) and coastal nonrefinery industrial wastes were estimated to contribute 0.3 MTA each. Better control of these effluents should reduce their quantities somewhat. Any such improvements presumably would also decrease the inputs from river runoff.

D. Tanker and Terminal Operations

The 1973 NAS report estimated that tanker operations contributed 1.833 MTA, or about 30 percent of the total. Of the total, 0.31 MTA resulted from tankers using load-on-top (LOT) procedures, if it was assumed that 80 percent of the tankers used LOT procedures and that LOT reduced potential discharges by 90 percent. Discharges from non-LOT tankers were estimated at 0.77 MTA. Discharges prior to dry docking were estimated at about 0.25 MTA. Terminal operations discharges were estimated to contribute 0.003 MTA, and bilges and bunkering 0.5 MTA.

1. Tanker Accidents

Total spillage from year to year varies widely, depending upon the occurrence of major accidents. The NAS estimated 0.2 MTA in 1973 and predicted decreased spillage from accidents due to new ships with improved navigational and communication aids. That report also predicted that improved marine vessel traffic systems should reduce ship collisions near ports. Recent evidence has shown that this reduction has not occurred. Quantities spilled in 1978, 1979, and 1980 were 0.7, 1.1, and 0.5 million tons, respectively.[34] Often, a single large spill contributes a significant percentage of the total. A brief description of three such spills follows.

a. Torrey Canyon

On March 18, 1967, the tanker *Torrey Canyon*, loaded with 119,000 tons of Kuwait crude oil, ran aground on the Seven Stones Reef off the southwest coast of England. Initially, 30,000 tons of crude oil escaped to the sea. During the next seven days, another 20,000 tons were lost. On March 26, the *Torrey Canyon* broke up

during salvage operations and released approximately 50,000 tons. Thus about 100,000 tons in total of crude oil were spilled into the sea.

b. Amoco Cadız

The Liberian tanker Amoco Cadiz, which had a load capacity of 233,690 tons, lost steering in a storm on March 16, 1978, off the Brittany coast. After drifting for 12 hours, the tanker struck rocks approximately 1.5 kilometers off Portsall, France, and shortly began to spill oil. Eventually the entire load of 223,130 tons of Arabian Light and Iranian Light crude oil plus 4,000 tons of bunker fuel oil were lost. Strong westerly winds pushed the spilled hydrocarbons to the east. Eventually over 390 kilometers along the northwestern coast of France were contaminated by the spilled oil.

c. Atlantic Empress

The collision of the Atlantic Empress and the Aegean Captain in the Caribbean Sea in 1979 illustrates the fact that a major spill need not result in significant harm to the environment. Even though the Atlantic Empress eventually sank, and her entire cargo of 276,000 tons of crude oil was lost, no harmful pollution resulted. This fortunate result was brought about by a coordinated response effort following the collision, correct decisions regarding a towing course for the stricken vessel and letting the fire continue to consume nearly all of the oil, plus considerable assistance from natural forces.

2. Nontanker Accidents

Although there are about nine times as many nontankers as tankers, most of the former are much smaller and normally carry only bunker fuel. They are estimated to lose 0.1 MTA by collision or sinking. Although navigation facilities should be improved, little change is expected in this estimate as human error remains the major factor.

E. Offshore Production

The worldwide input of oil to the oceans from offshore drilling and production operations was estimated by the NAS in 1975 to be 0.08 MTA. Of that amount, 0.02 MTA was estimated to be from minor spills and discharge of oil field brines during normal drilling and production. As offshore oil production increases worldwide, these normal discharges will probably increase proportionately.

Four elements have been identified as necessary for safe drilling operations: well trained, experienced personnel at the rig; good equipment; adequate emergency training; and a company representative capable of making decisions on site when difficulties are encountered.

1. Blowouts

Blowouts during drilling operations have historically been rare. In the 1971-1978 period there were no oil well blowouts in the U.S. Outer Continental Shelf (OCS) and Alaska during drilling of exploratory wells. During the same period, three blowouts occurred during production operations with a total spillage of 725 barrels. There have been some incidents of major spills during production operations, such as the Ixtoc-I blowout in the Bay of Campeche, Mexico (1979), and the Santa Barbara Channel blowout (1969).

a. Ixtoc-I Blowout

On June 3, 1979, the Ixtoc-I well blew out in the Bay of Campeche, Mexico. Study of this blowout revealed that mud supplies, a critical safety component, were in short supply on the rig. Inadequate equipment and inexperienced personnel were also found to be factors in the incident, all prerequisites for safe drilling. Before the well was capped on March 23, 1980, approximately 530,000 tons of oil were spilled, the largest spill into the marine environment ever documented.

b. Santa Barbara Blowout

On January 28, 1969, during normal development of a prospective petroleum-bearing oil pool on the Rincon structural trend about 6.5 miles southeast of Santa Barbara, California, a gas blowout occurred during completion of an offshore well. Until February 7, when the well was shut in by cementing, uncontrolled flow led to local oil pollution as some 1,000 tons of oil were lost to the sea. Reservoir damage during this period caused a subsequent moderate and steady oil seepage from the sea floor, estimated to be at a daily average rate of 5 tons, that in turn caused a continual slick on the surface. This seepage was substantially reduced by early September 1969 to less than 2 tons per day as a result of a drilling and grouting program.

F. Natural Marine Seepage

The 1975 NAS estimate for crude oil seepage of 0.6 MTA is principally based upon a 1974 evaluation for the continental shelf areas of the world.[35] This estimate does not include oil derived from land sources such as breached reservoirs or sub-aereal erosion of tar sands, asphalt, and source rocks containing liquid petroleum. The estimate also does not include marine gas seeps that contain some liquid hydrocarbons, which have been detected by marine seep-surveys and geophysical techniques. There is recent evidence that seeps may contribute more than that estimate. The recent discovery of a large subsurface oil-rich layer at a 200-meter depth off Venezuela was estimated to contain 1 million tons of weathered crude oil[36] It was reported to have originated from a natural marine seep. Resampling a year later, however, found no oil, but found high concentrations of hydrocarbon-oxidizing bacteria.

Hydrocarbon contributions from biogenic sources probably far exceed those from seepage. The production of hydrocarbons from many types of plants, animals, and microorganisms has been documented.

G. Atmospheric Fallout

The total worldwide input of petroleum-derived hydrocarbons to the atmosphere was estimated by the NAS to be about 70 MTA. This estimate was based on a detailed inventory of hydrocarbon emissions by the National Air Pollution Control Administration in 1968 and on similar studies in Sweden. These emission levels were scaled to world proportions based upon energy patterns. Approximately two-thirds of the total, about 45 MTA, emanates from transportation sources.

The amount of hydrocarbons contributed to the surface environment from the atmosphere is one of the most uncertain estimates. Little is known about atmospheric reactions and reaction rates and the amount of atmospheric hydrocarbons adsorbed onto particulates returned to the earth's surface. The assumptions used indicated that approximately 4 MTA of hydrocarbons were available to return. Estimates of distributions were based on the relative areas of land to oceans, global precipitation patterns, and the fact that particulates are more concentrated over land than over oceans. Thus, 0.6 MTA was estimated to fall on the ocean and the remaining 3.4 MTA on the land.

These estimates may be refined by more accurate and diagnostic analysis methods for river and urban runoff, seepage, and atmospheric fallout. However, such studies are not likely to significantly change the overall current estimates.

II. Amounts of Hydrocarbons in the Marine Environment

A basic question that remains unanswered is the level of petroleum hydrocarbon input to an ocean area at which serious long-term damage might occur. The sea is an enormously complex system about which current knowledge is imperfect. The ocean may be able to accommodate petroleum hydrocarbon inputs far above those occurring today. On the other hand, the damage level may be within an order of magnitude of present inputs to the sea. Until this basic question is answered, it seems wisest to continue efforts in national and international control of inputs and to accelerate research to reduce the current level of uncertainty.

A. Hydrocarbons in Water

Typical concentrations of hydrocarbons in the environment are shown in Tables 76 and 77.

1. Low-Molecular-Weight (Volatile) Hydrocarbons

Over a seven-year period, approximately 500 surface water samples from the Atlantic, Pacific, Antarctic, Gulf of Mexico,

TABLE 76

Average Concentration of Hydrocarbons in Water*

Hydrocarbon Species	Micrograms Per Liter
Methane	0.003
Ethane	0.0007
Ethylene	0.006
Propane	0.0007
Propylene	0.003
Butanes	0.0001

*Sources of data: Swinnerton, J. W.; Linnenbom, V. J., "Gaseous Hydrocarbons in Sea-Water: Determination," Science, 1967, 156: 1119-1120; Swinnerton, J. W.; Linnenbom, V. J.; Cheek, C. H., "Distribution of Methane and Carbon Monoxide Between the Atmosphere and Natural Waters," Envir. Sci. & Tech., 1969, 3: 836-838; and Swinnerton, J. W.; Lamotagne, R. A., "Oceanic Distribution of Low-Molecular-Weight Hydrocarbons - Baseline Measurements," Envir. Sci. & Tech., 1974, 8: 657-663.

and Caribbean were analyzed by Swinnerton and coworkers.[37,38,39] The surface water concentrations remote from possible sources of contamination were consistent from area to area, suggesting steady-state conditions. Concentrations of the saturated light gases were higher in areas suspected of biogenic and/or petroleum contamination, such as the Mississippi River and Potomac and Chesapeake Bays. Some low-molecular-weight hydrocarbons have been measured in localized areas around oil-producing operations.[40,41]

Depth profiles to 500 meters have been made in both the Atlantic Ocean west of Ireland, and in the Gulf of Mexico south of Mobile, Alabama. Methane concentrations ranging between 0.03 and 0.05 micrograms per liter (μg/l) in the Atlantic were constant with depth. Concentrations in the Gulf of Mexico were up to 0.06 μg/l at the surface, increasing to 0.20 μg/l at 30 meters and then decreasing with greater depth.

Relatively uniform ethylene and propylene concentrations in the open ocean and near shore were reported, even in those areas containing higher concentrations of saturated hydrocarbons.[42] In general, the concentrations of ethene and propene decreased with increasing depth, reaching trace levels at 150 to 200 meters. In Atlantic, Caribbean, and Pacific depth profiles, these unsaturated hydrocarbons often showed maximum concentrations between 30 and 100 meters, particularly in spring and summer.

Marine gas seeps have been measured throughout the world.[43,44,45] These seeps often produce anomalies several hundred times the general background values for methane-through-butane hydrocarbons.

TABLE 77

Concentration of Hydrocarbons in Sediments*

Area	Water Condition	Concentration (Micrograms Per Liter)
Cook Inlet	Pristine	<1,000
Fort Valdez	Pristine	2,000
Continental Shelf	Clean	40,000-60,000
Continental Slope	Clean	10,000-32,000
Continental Rise	Clean	1,000-5,000
Saginaw Bay	Marginal	400,000
France	Marginal	400,000
San Francisco Bay	Polluted	1,000,000
Lake Maricaibo	Polluted	3,000,000

*Sources of data: McAuliffe, C. D., "Surveillance of the Marine Environment for Hydrocarbons," Mar. Sci. Commun., 1976, 2: 13-42; Farrington, J. W.; Meyers, P. A., "Hydrocarbons in the Marine Environment," In Environmental Chemistry, Vol. I., G. S. Eglington, ed., The Chemical Society: London, 1975; and Smith, P. V., Jr., "Studies on Origin of Petroleum: Occurrence of Hydrocarbons in Recent Sediments," Bull. Amer. Assoc. Petr. Geol., 1954, 38: 377-404.

2. High-Molecular-Weight (Nonvolatile) Hydrocarbons

High-molecular-weight hydrocarbons have been measured in some ocean areas, using several sampling techniques: filtering out particles of oil with neuston nets; capturing air/sea interface hydrocarbons by screen or teflon disk, and very-near-surface particles with slurp bottles; sampling the near surface (to about 10 meters) by opening submerged bottles or sampling devices, or by pumping; and wire line sampling (depth profiles).

a. Particulate Hydrocarbons

Particles of floating tar, variously called tar lumps, tar balls, particulate oil, and pelagic tar, have been collected with neuston nets from a number of areas. These include the northwest Atlantic, North Atlantic, East Coast Continental Shelf, Caribbean, Gulf of Mexico, Sargasso Sea, Mediterranean, and Pacific. Concentrations varied from less than 0.2 micrograms per square meter

(μg/m²) for portions of the eastern Pacific and North Atlantic margins to as high as 5 μg/m² in the Mediterranean. The Sargasso Sea had a mean value of about 2 μg/m².

b. Hydrocarbons at the Sea Surface

Researchers, using a screen for collection, measured hydrocarbons at the air/sea interface (0.1 to 0.3 millimeter layer) and found an average concentration of 155 μg/l in the Atlantic and Sargasso Sea.[46] Other researchers, using a teflon disc for collection at the interface, found average values of 360 μg/m², but only 180 μg/m² off Florida.[47] Average values for offshore Louisiana varied from 210 to 700 μg/m². Using slurp bottles and sampling a layer from 0 to 3 millimeters or 0 to 5 millimeters, high-molecular-weight hydrocarbons were measured in the northwest Atlantic and on a transect from Nova Scotia to Bermuda.[48,49] Their values averaged 9 to 20 μg/l of high-molecular-weight hydrocarbons in this near-surface water.

c. Hydrocarbons in the Water Column

Near-surface samples were collected by pail along tanker routes from the Caribbean and the Gulf Coast to New York.[50] These and later samplings in the Pacific and Indian Oceans averaged about 9 μg/l.[51,52] Samples collected at 10 meters by pump averaged about 4 μg/l. Concentrations of 0.7 and 0.4 μg/l, respectively, were found at 1 meter and 5 meters on transects in the northwest Atlantic from Nova Scotia to Bermuda.[53,54] Below 5 meters they were unable to truly distinguish hydrocarbons from possible sample contaminants and indicated that no measurable hydrocarbons existed below 10 meters. Samples dipped from the ocean surface were found to contain an average 0.2 μg/l.[55] Researchers were unable to detect hydrocarbons throughout the water column of the Cook Inlet, using a method sensitive to 0.02 μg/l.[56] In the Coal Oil Point seep area (Santa Barbara Channel), relatively low values were reported.[57] Concentrations were 16 μg/l at 1 meter, and less than 1 μg/l from 10 to 55 meters. In non-seep areas concentrations averaged 0.3 μg/l from 1 to 400 meters.

From these investigations, the data show that concentrations at 5 and 10 meters are about 40 percent of those found in surface dip samples (0-0.3 meter) and 1 meter,[58] suggesting that most of the hydrocarbons are particulate rather than in true solution. They may be adsorbed on particulates or absorbed into living matter.

B. Hydrocarbons in Recent Marine Sediments

Hydrocarbons in recent marine sediments can have several origins: subsurface seepage; bacterial generation of methane, with low amounts of ethane and propane; terrestrial and marine plant and animal remains; particulate matter from erosion of sedimentary rock in which petroleum hydrocarbons were previously generated; and hydrocarbons from atmospheric fallout. Recent marine sediments almost always contain three or four orders of magnitude higher hydrocarbon concentrations than does the overlying water.

1. Low-Molecular-Weight Hydrocarbons

The biogenic generation of methane and trace amounts of ethane and propane has been documented.[59] Butane-through-heptane hydrocarbons greater than 1,000 μg/l have not been detected in recent sediments except in seep areas, so they are probably not formed biologically. These hydrocarbons appear to form from organic matter subjected to depths of burial exceeding 1,000 meters at temperatures in excess of 50°C. Amounts greater than 1,000 μg/l in recent sediments are assumed to have migrated from deeper source sediments or petroleum reservoirs.

2. High-Molecular-Weight Hydrocarbons

Nearshore continental shelf sediments contain an estimated 40,000 μg/l of hydrocarbons.[60] The saturates fraction (alkane) is reported to be 40,000 to 60,000 μg/l on the continental shelf, 10,000 to 20,000 μg/l on the continental slope, and 1,000 to 5,000 μg/l in deep water sediments (sampled near Bermuda).[61]

An average of 32,000 μg/l was found in four samples in 120 to 920 meters of water off the west coast of Africa.[62] Fairly uniform hydrocarbon concentrations were found down to 100 meters in two recent-sediment cores from the Gulf of Mexico, off Louisiana. The data suggest that the contribution of hydrocarbons to sediments has been relatively constant in recent geological time. However, local sources of hydrocarbons in bays or rivers cause locally high concentrations of hydrocarbons in near-surface sediments. Areas studied include: France;[63] the Santa Barbara Channel, Coal Oil Point Seep area;[64,65] San Francisco Bay;[66] Lake Maricaibo;[67] Saginaw Bay;[68] Lake Washington;[69] and the Providence River.[70] In remote areas of the Cook Inlet, where samples consisted mainly of sand, gravel, and rocks, hydrocarbon concentrations of less than 1,000 μg/l were found.[71] Soft sediments at Port Valdez were found to contain an average of 2,000 μg/l.[72]

FATE OF OIL SPILLS[73]

Once oil is spilled, it immediately begins to undergo many complex, competing, and interacting physical, chemical, and biological changes. These changes include spreading, evaporation and solution, sedimentation, dispersion into droplets and particles, emulsification, chemical photooxidation, biodegradation by microorganisms, uptake by marine organisms, and formation of tarry lumps and particles.

I. Spreading and Movement

Oil slicks spread over the surface of the ocean at rates influenced by gravity, surface tension, viscosity, pour point (i.e., temperature of solidification), wind, waves, currents, and temperature. Water motion and wind elongate, distort, and break oil slicks into moving patches that are thickest near their leading edges. The oil slick velocity is the resulting component of the

wind velocity and that of the immediately underlying water. Wind moves oil between 2.5 and 3.5 percent of its velocity, with most values near 3 percent.[74,75]

II. Evaporation and Solution

The first compositional changes in petroleum spilled on water are evaporation and solution of volatile components. The rates and extent of these changes depend upon the chemical and physical nature of the petroleum, wind velocities, sea states, and water temperatures. Evaporation and solution are simultaneous and competitive with evaporation predominant; each volatile hydrocarbon's rates will depend upon its vapor pressure and solubility.

III. Sedimentation

Sedimentation is the process whereby particles of floating oil sink to the bottom of the sea. In order for this to occur, it is necessary for the oil particles, which are less dense than seawater, to be modified by evaporation of lighter components and, more important, by incorporation of particulate matter present in the water column. Sinking of oil droplets through the water column can only occur in the special cases where the density of the crude oil is already close to that of seawater. Because of the low levels of particulate matter present in the open sea, sedimentation is not likely to occur there. This process becomes more important in near-shore areas where the suspended sediment load in the water column may be high. Particularly high sediment loads may be contributed near shore by tidal or estuarine flows, land runoff, and storm conditions. Floating oil particles also can contribute to subtle sedimentation by impacting the shoreline, adhering to beach sand, and then moving back into the coastal waters by wave action.

IV. Dispersion

Depending upon the type of crude oil involved, spontaneous formation of small droplets of oil in water can occur due to wave and wind action. Natural dispersion can be helpful in mitigating the effects of spilled oil by dissipating the oil and thereby reducing its toxicity towards marine life. Once formed, dispersions tend to disappear from the surface, but remain in near-surface waters, where further dilution occurs.

The gradual spontaneous disappearance of spilled crude oil from the surface of the sea is assisted by dispersion processes. Because of the greatly enhanced oil/water interface, the small particles (globules) of oil created are more easily biodegraded by microorganisms, lose their more toxic, volatile components more readily than do continuous patches of oil, and are rapidly dissipated by the diluting action of the sea. The rapid dilution of dispersed oil often prevents the oil from traveling as far as surface slicks, and thereby reduces the likelihood of its reaching coastal areas and washing ashore. Dispersion also reduces the hazard to marine birds.

V. Emulsification

The formation of emulsions of water in oil leads to many difficulties. The tendency to form emulsions depends upon the type of oil involved, but is promoted by rough sea conditions. Their formation adds to the difficulty of cleanup, onshore and offshore, because it increases the volume and viscosity of material to be removed and, therefore, the difficulty in handling and disposing of the oil.

VI. Chemical Photooxidation

Oil subjected to the rays of the sun on the surface of the sea undergoes chemical changes generally termed chemical photooxidation or photochemical oxidation.[76] These changes degrade certain components of the oil and render them more water-soluble and subject to dissipation by solution and dilution. The rates of chemical photooxidation of oil are greatest at the sea surface or on physically stranded, exposed oil.

VII. Biodegradation

Water and sediments throughout the world contain microorganisms (bacteria, yeasts, and fungi), which utilize and degrade petroleum components. A very large number of species of microorganisms that can degrade petroleum have been identified in open sea and coastal areas.[77]

Biodegradation is the most important of the processes that account for the ultimate fate of oil in the marine environment, although it does not immediately decrease the volume of oil or its impact on the environment after it is spilled. Biodegradation is promoted by dispersion of oil slicks into small particles of high surface area. This applies whether dispersion occurs naturally or is induced by application of dispersants.

VIII. Uptake by Marine Organisms

Most marine animals (finfish, shellfish, zooplankton) can ingest and absorb hydrocarbons from the oil present in their environments. Some early researchers postulated that the oil components entering the tissues of these animals might be retained for long periods, and perhaps permanently. Recent studies have shown that these oil components are in some cases taken up rapidly from hydrocarbon-contaminated environments, but are rapidly purged. In fish, hydrocarbons may also be transformed into different substances by metabolic processes.[78] These findings have led to two major conclusions:

- Marine organisms do not retain oil for long periods of time.

  There is no evidence that food chain accumulation (an increase in tissue hydrocarbon levels when larger organisms eat many smaller organisms contaminated with oil) occurs.

EFFECTS OF OIL SPILLS IN THE MARINE ENVIRONMENT

I. Open Ocean Spills

Major spills in the open ocean are more likely to involve crude oils, which constitute the largest volume of oil transported by sea. Crude oil spills can also occur from offshore blowouts and pipeline breaks. Although fish and bottom-dwelling (benthic) organisms may be present in large numbers, scientific investigations have indicated no adverse effects on adult fish or other macroorganisms. The dilution potential of the open sea and the dispersion, weathering, and loss of toxic constituents make it improbable that oils spilled in deep-sea areas could reach benthic marine life, much less in toxic amounts.

The two potential dangers posed by oil in the open sea are effects on sea birds and on plankton (algae eggs, larvae, and fry of adult animals, some of which inhabit near-surface water). These life forms are numerous and are subject to high natural mortality. The impact of an oil spill would probably not be sufficiently large to affect adult populations widely or for long.

Concern has been expressed that a number of biological effects can result from the large amounts of oil entering the sea, whether from oil spills, other sources attributable to man, or from natural seeps. Such postulated effects include disruption of bacterial populations, oil layer phenomena that would prevent normal gas exchange at the sea surface, local heating effects caused by solar heat absorption in oil slicks, and concentration of pesticides and heavy metals by oil. Despite careful study, no evidence has been obtained to support these claims.[79] Fears of permanent and extensive mortality of marine animals from oil spills have not been substantiated.[80,81,82]

II. Coastal Spills

Oil spills that impact near-shore areas have shown effects on sea birds and, in some instances, benthic organisms.[83,84] Improper measures taken to remove the oil can inflict losses in these localized areas exceeding those due to the oil itself, and which may permanently alter a localized habitat.

The following factors affect the seriousness of biological damage from oil:[85]

- Amount of oil impacting the area.
- Type of oil spilled -- Crude oils are less toxic than most refined products.
- Hydrology and tidal range -- A large tidal range generally (though not always) results in faster oil removal due to natural flushing.

- Weather and sea conditions -- Unusually high waves or rapid currents resulting from storms may cause oiling of areas not otherwise likely to be impacted.[86]

- Season -- If species with a restricted annual breeding season are affected during that season, repopulation must await the next annual cycle and will be delayed.

- Geography of the area -- For example, the large tidal range and presence of crenulate bays and tombolos caused localized trapping of oil during the Amoco Cadiz spill.[87,88]

- Types of local marine flora and fauna -- As discussed later in this chapter, certain environments or populations are more sensitive to stress than others.

- Previous exposure of the area to oil -- Similarly, areas exposed to other pollutants may be more susceptible to damage, or slower to recover.[89]

- Treatment of the spill -- Cleanup techniques, if improperly applied, may compound problems.[90]

The greatest damage to marine life will occur when:[91]

- The oil is spilled into, or reaches, a confined, shallow body of water, such as a small bay; that is, the volume of oil spilled is large with respect to the body of water being impacted.

- The oil is a light, refined oil such as a home heating oil or a diesel fuel.

- There is a high load of fine sediment in the water column due to storms, heavy surf, or the discharge of rivers.

Spills in which all of these conditions occurred simultaneously are rare. Examples include the spill near West Falmouth, Massachusetts, in 1969,[92-95] and at Baja California, Mexico, in 1957.[96] In both cases the benthic life experienced heavy immediate mortality and their populations were reduced locally for several years.

Many spills that appeared to threaten long-term major effects have not produced them. Examples of such spills include the Santa Barbara spill and the San Francisco Bay tanker spill.

Near-shore oil spills involving crude oils, such as the Amoco Cadiz, Torrey Canyon, and Metula spills, do inflict substantial biological damage, but such damage is mitigated by the lower toxicities of crude oils compared to some refined products. However, some fresh crude oils, prior to weathering, may be as or more toxic than No. 2 fuel oil, for example.

Oil pollution poses much less of a threat to the marine environment than its presence and visual prominence would imply. Even though the information on sources, fates, and effects of oil in the environment is not complete, the subject is sufficiently understood to suggest that human health hazards appear to be insignificant and that effects upon marine organisms are not likely to be of long duration or observable as affecting total populations of impacted species or ecosystems in the zone of influence of the oil. Careful study may reveal subtle long-term effects, which, however, are believed to have had little ecological consequence.

A. Short-Term Effects

1. Immediate Mortality

Extensive biological literature documents the deaths of plants and animals as a direct and immediate result of acute oil pollution. Whether or not this mortality (which can be massive) has any significant long-term effects on the population of a species depends upon several factors. One important thought that is rarely considered is the reproductive biology and population dynamics of the species.

Many marine organisms produce young on a very large scale (cod, 4,000,000 eggs per year for several years; oysters, 8,000,000 eggs per year), although only a few of them normally survive to adulthood. Provided the stock is not so depleted that recruitment is limited by egg production, the effects of density-dependent mortality are likely to compensate for additional density-independent losses such as by oil pollution. In a practical example, the eggs and developmental stages of many commercial finfish spend some time in the neuston layer where they can be exposed to oil and a variety of pollutants harmful to them. Comparable assessments are rarely available for noncommercial fish and invertebrates, but there is no reason to suppose that any numerous, fecund species is materially affected by losses of eggs or larvae due to oil pollution.

However, an alternative reproductive strategy is practiced by many marine invertebrates (boreal and sub-boreal) -- the production of small numbers of young that are rarely dispersed in the neuston layer as eggs or larvae, but are retained close to the parents and serve to replenish their originating populations. Local pollution damage has therefore greater significance for such species. If small numbers of young are produced, their loss is likely to depress recruitment because they do not become widely dispersed.

The deaths of adults reduce the local population and, if the adults are sexually mature and close to reproduction, their potential offspring. Mobile species with a short generation time quickly repopulate an affected area from neighboring areas, once the source of damage has been removed. A number of sea bird species have a population of nonbreeding sub-adults that will move in to replenish a depleted breeding stock.

Repopulation of damaged areas is necessarily slow for species that are relatively immobile as adults and lack dispersive larval

stages. Thus, although the major features of a damaged ecosystem may be restored within two or three years, the re-establishment of some fauna and flora may take much longer.

2. Sublethal Effects

Assessment of the toxicities of petroleum hydrocarbons for marine organisms by standard laboratory tests has been refined and extended to cover sublethal effects.[97] Reduced viability in animals exposed to low concentrations of petroleum might be expected to result in a hidden additional mortality. However, assessing this in a natural environment is even more difficult than assessing deaths caused directly by pollution.

For example, a number of studies have shown that ingested petroleum oils cause liver and kidney damage in gulls and some other sea birds. However, despite exposure to oil pollution for several decades, most gulls in northwestern Europe are increasing in numbers to the point where they have become pests in some areas, and attempts are being made to control their numbers. Although it might be argued that populations would be even higher in the absence of pollution, it is evident that if sublethal effects are caused by ingested oil, they are not significantly impairing the survival of these species.

In a number of countries, control agencies are setting effluent standards increasingly in terms of sublethal threshold levels. In a number of instances, this standard has been applied to refinery effluents and production water discharges at offshore platforms.[98] It is not clear that laboratory "sublethal" levels of pollutants have any significant effects in nature. The application of these standards to offshore production and refinery effluents shows extreme and sometimes unreasonable caution, and may be extremely wasteful of resources.

Research efforts should, therefore, be directed toward discovering the impact of pollutants at sublethal concentrations on populations of marine organisms and ecosystems. This focus will make the laboratory investigations more relevant and aid in setting biologically realistic effluent discharge standards.

B. Long-Term Effects

Ecological effects of a variety of oil spills and other discharges have been reported in numerous publications.[99-103] Effects have ranged from temporary, localized kills of some shore communities to enhanced growth of some species of phytoplankton. Factors that influence the spill impacts cited previously include the type of oil discharged, its volume, location, and methods of cleaning (such as burning, chemical removal, dispersant spraying, and mechanical recovery); hydrographic conditions; weather; types of biological communities present; and time of year.

1. Shoreline Effects

Immediate and short-term effects of several oil spills (including the use of dispersants) are fairly well established for many of the well known shore species, from pre- and post-spill surveys and field and laboratory experiments.[104-110] Less is known of the long-term effects because seasonal and natural variations in many intertidal organisms are difficult to separate from the effects of oil spills. Although the seasons of annual recruitment for many common shore animals and plants are known, natural fluctuations in recruitment from year to year are still being studied.[111,112]

There are also long-term fluctuations in distribution and abundance that have sometimes been related to climatic changes. These fluctuations also complicate the interpretation of post-spill surveys. Initial observations along the shore at Dounreay (British Isles) following the release of 17,000 gallons of home heating oil indicated that 1,000 sea birds and 20 to 30 percent of the resident barnacle population were killed. Subsequent additional mortality was thought to be related to dispersant use. However, extensive baseline data for this area indicated a long-term population cycle that was missed by the spot surveys. When this was taken into consideration, the estimates of barnacle mortality were reduced by 50 percent, and no delayed mortality was found.[113]

In many cases, recovery of shore organisms from a single exposure to oil appears to be good, if not complete, in one to 10 years.[114-119] However, long-term effects have been documented for some oil spills. Following the Torrey Canyon spill, the age structures of some rocky shore populations showed some abnormalities for up to 10 years.[120] At some salt marsh sites, petroleum residues are still present in poorly oxygenated sediments after 12 years.

Although sandy beaches generally have limited biological communities, they may be important for recreational and scenic purposes. Beaches may be subject to wave actions that, depending upon the time of year, deposit or erode sand. Certain types of oil readily penetrate the sand, forming a band at some distance below the surface. In most instances, this oil is removed fairly rapidly and weathers as it is exposed and washed back into the sea. Such oil may have limited adverse effects on subtidal organisms close to the shoreline.

Although the intertidal zones on exposed high energy rocky coasts are rapidly cleaned by wave action, oil thrown beyond the upper high tide zone (splash zone) may persist for longer times. Studies of the biological effects of oil in the intertidal zones of beaches, tidal pools, and splash zones have not revealed any serious long-term ecological threat.[121,122]

Cleanup procedures can cause adverse effects in various habitats, e.g., marshes and mudflats.[123] Following the Amoco Cadiz oil spill, a heavily oiled marsh was cleaned using heavoy equipment that removed much of the surface sediment, exposing the granitic

basement. This method of cleaning has led to a marked alteration of the marsh morphology, opening the area to increased wave and current activity and resultant erosion.[124] Recovery has been severely impaired. Much evidence shows clearly that no cleanup would be preferrable to such techniques.[125] Ecologists should provide guidance for cleanup in these types of areas.

C. Special Populations and Environments

Because of their proximity to spills, higher than normal sensitivities, or public interest, certain populations and environments deserve special consideration.

1. Commercial Species in the Plankton

Plankton include phytoplankton (plants) and zooplankton (animals). Zooplankton include the eggs, larvae, and fry of adult animals that normally inhabit deeper waters. Neustonic organisms (neuston is an inexact term) generally live very near the surface. It has been shown that the surface film of the sea is enriched with dissolved organic carbon and carbohydrate.[126] This film contains a diverse population of bacteria and amoebae. Many organisms of commercial importance are neustonic in their early stages. The floating eggs of pelagic fish (cod, plaice, and haddock) may be in direct contact with the surface film in calm conditions. Many crustacean larvae, including those of crabs and lobsters, are also neustonic.[127]

Lobster larvae normally live in the top 20 centimeters of water. They eventually sink to the sea floor. Continuous laboratory exposure of lobster larvae to 1 part per million (ppm) of fresh oil throughout their first four stages of development resulted in approximately 50 percent lower survival than in control larvae or those exposed to only 0.1 ppm crude oil in seawater. Those exposed to 0.1 ppm were entirely normal in their behavior, development, and survival, except for color. They turned from their normal, almost transparent pale blue to a light red. In assessing the significance of these data, one should remember that it is difficult to maintain concentrations as high as 1 ppm of fresh oil in the water column under an oil slick.[128,129,130]

Numerous laboratory studies on effects of oil on zooplankton have reported a number of effects: impaired fertilization of eggs (sea urchins); abnormal development in larvae, including the inability to molt in crustaceans; impaired embryological development in sea urchin eggs; abnormal embryos in herring eggs; lowered survival of organisms, from protozoans to larval fishes; modified respiration, growth, feeding, and swimming; increased body burdens of hydrocarbons; and changes of species abundances and composition.

These studies, however, have invariably used abnormally high concentrations of oils and/or their water-soluble fractions. These laboratory studies have value in comparing one product with another and determining possible effects on organisms. They have little value for extrapolation to possibly adverse effects of low levels of hydrocarbons in waters under spill situations.

Studies in a chronically polluted area of the eastern Mediterranean found that near-surface zooplankton ingested oil.[131] The total lipids in zooplankton were 33 percent in the polluted area and only 5 percent in uncontaminated areas. These hydrocarbons appear to have had no measurable physiological effects.

Phytoplankton exposed to either single hydrocarbons or whole oils have shown stimulation at low levels, and at high levels inhibition of population growth in cell numbers or carbon fixation;[132-135] extension of the lag phase of growth;[136,137] and other physiological effects.[138]

In large plastic cylinders immersed in seawater, oil was shown to have indirect effects on plankton. Fuel oil added initially at 20 ppm caused replacement of the dominant diatom by a microflagellate.[139] Similar results were shown in large tanks of seawater.[140] Due to the dilution and dispersion processes in natural environments, the results, based on steady-state exposures in enclosures, may not be comparable to real-life occurrences.

During 1978 and 1979, east and west coast oil spill research shipboard survival tests were conducted using natural zooplankton populations. In the 1978 southern California tests, one species from a varied natural population of zooplankton showed significant mortality in water from under the untreated oil slick. A second species showed significant mortality in water from under both the untreated and treated slicks. The experimental and control animals of other species showed no differences in mortality. The 1979 east coast tests showed no effects on zooplankton, including those obtained from under chemically dispersed oil slicks.

The Argo Merchant spilled 26,000 tons of residual fuel oil at a critical time for fish reproduction on the Georges Bank. A slick 12,000 square miles in area was predicted by some to result in disastrous ecological effects. Although the effects of that spill were measured under less than optimum conditions, no adverse effects on fish populations have been proven or are projected.[141]

In a study by the Massachusetts Institute of Technology, the probable biological impact of a 10,000-ton oil spill in the Georges Bank would be the loss of less than 1 percent of a year class of cod and haddock larvae. These are the species of highest spawning concentration in this area. The study concluded, "It appears unlikely that a single large spill will have a noticeable effect on a population of an individual species, especially in view of the fact that these species produce many more offspring than the environment can support at adulthood."[142]

More information is needed about the characteristics of the actual planktonic and neustonic environments. Factors such as wind and wave action need to be studied. Organisms in the neustonic zone may well be exposed in calm waters; particularly buoyant fish eggs, which may come into immediate contact with oil. Even if such contact is lethal, however, it may well be relatively unimportant at the local population level unless spawning and drift zones are regularly or widely polluted.

Obtaining information from field studies is difficult, but it is impossible to simulate the neustonic environment adequately in a laboratory. The lack of field data is probably largely responsible for the poor state of current knowledge.

2. Sea Birds

Because of public interest and the conspicuous nature of the casualties, the loss of sea birds through oil pollution attracts more attention than any other pollution-induced mortality in the sea. Species most at risk from oil pollution are the gregarious diving birds: auks (guillemot, razor bill, and puffin), divers, grebes, some diving sea ducks, and occasionally cormorants and shags. Other species are rarely affected in large numbers.

The most significant threat is from floating oil, which damages the waterproofing and insulating properties of the plumage. Death is by drowning, starvation, hypothermia, or pneumonia. Contaminating oil on the plumage may be transferred to the eggs of nesting birds and prevent hatching. Ingested oil has been shown in laboratory studies to cause renal, liver, and intestinal damage; however, there is no evidence that the latter factor has caused significant damage to avian populations.

While large oil spills occurring when the birds are congregating cause numerous and well-publicized casualties, quite small oil slicks, especially of refined products, that persist and move with the tides may cause comparable losses. It seems highly probable that such factors as tanker washings, oily bilge water, and accidental discharges from coastal storage tanks are responsible for many sea bird deaths. Chronic inputs of petroleum hydrocarbons to sea birds has been documented.[143] Losses are accounted for by the number of dead or damaged birds found on beaches, so these data are subject to considerable uncertainty. Many birds are lost before reaching shore, so the true loss may be greater than data indicate. Further uncertainty is introduced by birds washed ashore that died from other causes, but became oiled after death.[144]

Fears have been expressed that some populations are jeopardized by oil spills,[145] but relatively few species have been affected.[146] Auks, in particular, have a low reproductive rate, low adult mortality, and considerable longevity. On theoretical grounds, it is presumed that heavy adult auk mortality could not be compensated for quickly.[147,148] Breeding populations that are particularly at risk from oil pollution might be drastically reduced for a long time. For a number of years, it was thought that oil pollution had substantially reduced some populations. For example, in the 1960's it was reported that long-tailed ducks migrating through Finland had been reduced to a tenth of their former numbers[149,150] and that guillemot and razor bill colonies on the Newfoundland coast had declined catastrophically through oil pollution on the Grand Banks.[151,152]

The scientific evidence that breeding populations have been reduced by oil pollution has come under question. It is difficult

to make accurate counts of sea birds on cliffs, but sample censuses in 1969 and 1974 suggest that most colonies had stable numbers, or had increased by more than 10 percent. Few colonies had decreased by more than 10 percent.[153]

It is rather surprising that species with low reproductive potentials can withstand repeated losses without reduction of the breeding populations. Apparently young birds do not normally join the breeding colonies until they are four to five years old. A population of submature adults exists at sea, away from the breeding areas. The onset of reproductive activity may depend more upon social than physiological factors, with young birds moving in to replenish losses in the breeding population. This phenomenon is thought to underly the rapid increases in some auk colonies, increases too great to be accounted for by their breeding success.[154]

Similar phenomena probably explain the resilience of other species after losses from oil pollution. Eider ducks have a much greater reproductive potential than auks, but in most years only 10 percent of the chicks survive to fledgling size.[155] They remain attached to a particular breeding colony throughout their lives. Despite this, the loss of 25 to 33 percent of breeding eider in the Aaland Island (Gulf of Finland) to oil pollution appears to have been without long-term effects, as the breeding population was fully restored in the following year.[156]

There have been substantial declines in auk colonies in southwest England, Wales, and Brittany. Such colonies are at the southern fringe of the geographic ranges of these sub-Arctic species, and their distributions have been contracting northward. This trend appears to have begun in the last century, before the onset of serious oil pollution, perhaps as a result of climatic changes Oil pollution may have hastened the disappearance of some of these southern colonies, most conspicuously puffin colonies in Brittany, following the *Torrey Canyon*, *Amoco Cadiz*, and other pollution incidents.

In summary, contrary to earlier expectations, it is now evident that losses of sea birds through oil pollution and other causes, though heavy, have had no detectable impact on breeding populations. The declines of some sub-Arctic species do not appear to have been primarily caused by oil pollution.[157]

3. Mangrove Communities

Mangrove areas are vulnerable to oil spills because mangrove pneumatophores (breathing organs) are close to the water line and are easily affected by oil. Mangroves hold a key position in subtropical and tropical ecology, as reservoirs for nutrients that then pass to the offshore waters and as breeding areas for marine animals. Oil can be toxic to these other organisms in a swampy mangrove area, may disrupt the flow of nutrients in the sea, and could damage the mangrove trees themselves. If the trees are lost, the stability of the ecosystem may also be lost, including the shelters of assorted fish and shellfish.

Although mangroves have been damaged by oil spills, the rapid biodegradation of oil in tropical sediments and waters, along with the high productivity rate of mangroves, normally permit impacted communities to recover rapidly.[158,159,160] However, some damage may remain for at least several years.[161]

Because mangrove environments are difficult to clean, protection from oil spills should be given high priority in these areas.[162] Marshes and mudflats should be cleaned under the guidance of ecologists in these areas.

4. Coral Communities

These important ecosystems have been suggested to be sensitive to oil contamination.[163,164,165] Coral reefs offer natural protection to a variety of marine organisms, are highly productive, and these mature, diverse tropical communities could be slow to recover from severe damage. If the corals die, erosion results, with loss of the ecosystem and most of the dependent organisms; thus, protection of coral communities deserves priority consideration.[166]

Many coral areas around the world may experience oil pollution. There are a number of accounts of oil spills in their vicinities.[167,168] No deleterious effects on submerged coral reefs were observed after a major oil spill in the Florida Keys.[169] It was concluded that oil may represent only a minor threat to coral reefs, and submerged corals evidently sustain little impact.[170] Coral exposed by low tides could be damaged, but its mucous coating appears to provide partial protection.

In laboratory and field studies, it was demonstrated that reef corals and associated sea urchins are quite tolerant to oil.[171-174] Concentrations of petroleum hydrocarbons required to elicit significant sublethal biological responses were significantly higher than expected in the reef habitat, except possibly after a large oil spill. They also showed that corals have very limited ability to accumulate petroleum hydrocarbons and release them quickly when returned to clean seawater (a phenomenon similar to the flushing action generated by ocean currents). However, other studies have shown that depuration is slow and bioaccumulation might occur.[175]

Long-term or chronic oil pollution appears to have a greater effect on corals and coral reef ecosystems. Researchers report that coral reefs exposed to severe, chronic oil pollution in the Red Sea were detrimentally influenced and slower to recover from natural catastrophes.[176,177] Low species diversity in Red Sea corals from an area chronically polluted by oil has been shown,[178] suggesting a lack of recolonization by coral larvae.

III. Chronic Inputs

Industrial estuaries may receive frequent small spills or discharges. Problems can arise where many such spills affect the

same area of shore. In experimental plots, it has been shown that many salt marsh plants, including Spartina anglica, can withstand four light monthly oilings with fresh Kuwait crude oil, but decline with further oilings.[179] Another study has shown that lugworms are eradicated following four successive bimonthly experimental oilings with five liters of Kuwait crude oil per five-meter-square plot.[180]

In contrast, chronic exposure of a marine community to both fresh and weathered crude oil in the natural seep area of Santa Barbara Channel, California, caused no significant adverse effects upon growth rates, biomass, or the general health of the community.[181] The only adverse effect was on the breeding potential of a stalked barnacle. Coating of the organisms with oil caused heat absorption from the sun, increasing the organism's temperature. Greater numbers of organisms were consistently found in cores from the seep area, though community density fluctuations were the same at both stations. The differences between the two stations were greatest during periods of peak abundance.

In the seep area, the communities of organisms were living in sediments with greater than 10,000 ppm of petroleum. It was suggested that hydrocarbon-degrading and sulfite-oxidizing bacteria support a denser population of infauna.[182]

Short-term bioassays of early development stages of eggs of the starfish Patiria miniata from the seep and control areas did not demonstrate oil adaptation. Increased survival rates were found for adult mussels taken from the Coal Oil Point seep area, compared to control mussels exposed to oil in aquaria.[183] Also, only minimal adverse effects of seep oil on the benthic community in the seep area were shown.[184]

A. Refinery Effluents

Coastal refineries differ widely in age, size, and complexity. Their discharges therefore vary in amount and type, as do their treatments prior to discharge. Some non-U.S. refineries use only primary treatment (gravity separation), which removes most oil and coarse particulate matter. All others have additional means for removing oil (flocculation and dissolved air flotation), plus biological treatment (activated sludge and biological ponds). Final effluents comprise varying proportions of process, cooling, storm, and ballast water, and they may contain very small amounts of oil, phenols, sulfides, mercaptans, cyanides, ammonia, some heavy metals, inorganic salts, suspended solids, and possibly other substances. Metals and other "exotic" pollutants in effluents and runoff from industrialized areas along coastal waters complicate the interpretation of petroleum effects at the community level.

In most U.S. refineries, the effluent must meet varying strict discharge standards. For example, test species of fish must survive in undiluted effluents for discharge into San Francisco Bay. Survival in effluents diluted by one-half with seawater is required for discharge to Santa Monica Bay, southern California.

Some refinery effluents in the United Kingdom are less restricted. Ecological surveys in the discharge areas of coastal refineries (mainly with primary treatment) have shown that the number of species and/or individuals did not always decrease near the discharge point. The greatest changes are associated with high volumes of effluents discharged into sheltered conditions. Such changes may be reversed following effluent improvement. For example, a salt marsh denuded by refinery effluents in Southampton waters has shown partial recolonization following effluent improvement.[185]

Well-dispersed effluents from some modern air-cooled refineries cause no ecological changes, even with only primary treatment. These effluents are usually of low total volume, compared with those from pre-1960 refineries. Effluents from some of the older refineries have also not indicated adverse effects, probably because of better distribution into receiving waters.

However, dilution does not necessarily avert adverse effects. Unless the discharge ecosystem is capable of adequately degrading, metabolizing, and assimilating the compounds discharged, toxic levels can gradually build up.

B. Offshore Oil Fields

To date, routine monitoring in offshore oil fields has been confined largely to hydrocarbon levels in fish plankton, and macrobenthos in selected areas, and to species composition and abundance of seabed macrofauna. Relatively little work has been done on species composition and abundance of plankton, meiofauna, and fish.

In a 1977 study on the effects of produced water discharged from a platform separator into a shallow bay in the Gulf of Mexico,[186] the waters contained 10 ppm of hydrocarbons and the sediments contained 96 ppm. Numbers of both individual and species of benthic organisms were reduced within 150 meters of the platform and changes in organism abundance were noted for 18 months. This correlated well with naphthalene concentrations in the sediments. However, the oil field brine also contained many other constituents, such as phenols, metals, and high total dissolved solids.

Detection of long-term changes in benthic communities involves repeated surveys over a period of years. The first area to be monitored in this way was the Ekofisk oil field, where surveys were started in 1973.[187] By 1977 it was possible to map an impact area around the installations and describe in some detail the effects in terms of species composition and abundance.[188] It has not been possible to separate the effects of oil, per se, from other factors. For example, physical disturbance of sediment was implicated, and a slight increase in silt content close to the installations may have been caused by either the discharge of drilling mud or redistribution of sediments resulting from pipeline burial or anchorage.

The Gulf University Research Consortium conducted an offshore ecology investigation in the Gulf of Mexico. These extensive studies were unable to find any effect directly linked to long-term petroleum operations. The area's large natural variation and influences of discharges from the Mississippi River appear to have a much greater influence on the community structure and functions than do petroleum operations.[189] Oil spills due to blowouts in offshore waters appear to have produced no significant adverse sub-sea effects. Studies following the Chevron Main Pass Block 41 spill in the Gulf of Mexico showed no correlation between biological parameters, such as the number of benthic species, and the hydrocarbon content of the sediments. Extensive trawl samples showed no alteration in the annual life cycle of commercially important shrimp. Blue crabs were observed throughout the spill area, and the numbers and species of fish collected were comparable to prior surveys.[190]

The Ekofisk oil spill, in the deeper waters of the North Sea, also indicated no significant adverse sub-sea effects. Even the very large oil discharge from the Ixtoc blowout in the Bay of Campeche, Gulf of Mexico, appears to have had minimal or no adverse effects in offshore waters. These studies suggest that offshore oil spills are not likely to cause significant environmental damage except to birds, should any be present, and shorelines, if the oil should strand there.

IV. Significance of Oil Pollution[191]

The significance of any environmental pollutant depends upon its threat to human health and its damage to biological resources, commercial interests, and amenities. Health hazards associated with oil pollution, as discussed in the next section, appear to be insignificant. The following sections deal with damage to living resources in the sea.

The difficulty of assessing the biological impact of oil pollution includes that encountered in evaluating the impact of other pollutants. This is compounded by the extremely complicated and variable nature of oil. The precise composition of any petroleum oil or refined product begins to change from the moment of discharge, by physical weathering, bacterial alteration, and metabolism by other marine organisms. The difficulties of assessment are in part technical and could be reduced by improved knowledge of the functioning of marine ecosystems.

The technical difficulties arise in part from a mismatch between in situ field ecological and laboratory studies. The latter have reached a high degree of sophistication, but generally have not been related to ecological advances or to real-world conditions (e.g., concentrations of oil in the environment). It is often impossible to translate the laboratory results into real-life terms. In addition, recent developments in marine ecology have revealed a number of features of marine ecosystems, particularly in relation to natural fluctuations and genetic variability, which call for increased sophistication in pollution studies.

The following factors need to be considered before one can realistically and objectively assess the biological impact of oil on the marine environment.

A. <u>Human Health</u>

From time to time, fears have been expressed that polycyclic aromatic hydrocarbons (PAH) from oil, which may be carcinogenic, could accumulate in seafoods and so present an increased risk of cancer to humans.[192-196] Studies have shown that marine organisms, particularly bivalve mollusks, will take up PAH following a pollution incident. In the laboratory, whole tissue levels have increased by as much as 100 to 1,000 times background levels.

As discussed previously, mechanisms exist for depuration and/or metabolism of these accumulated PAH compounds Chronically accumulated aromatic hydrocarbons are only very slowly depurated by <u>Mercenaria</u>, in marked contrast to those accumulated by bivalves following temporary acute exposures.[197] This slow depuration could explain the relatively high tissue concentrations of PAH in bivalves from sites frequently exposed to oil and/or other pollutants.

Contributions of PAH from petroleum sources should be placed in perspective. On an oceanic scale, oil is only a minor source of PAH, compared to terrestrial runoff and atmospheric inputs. It only becomes important locally in cases of acute spills and discharges; and even then, in the context of any health hazard to man, normally only intertidal and immediately sublittoral organisms are affected.

Comparison of the average concentrations of PAH in marine animals and other foodstuffs show them to be similar, although many foodstuffs, particularly smoked meat and fish, generally have higher concentrations than marine animals.[198] Whether these concentrations of PAH constitute a health hazard is still undefined. It is apparently still a matter of debate whether there is any dose-response relationship for cancer induction in man, or a threshold dose below which carcinogens do not induce cancer. If, for example, there is an effective threshold for intake of PAH, the critical question remains whether this threshold is exceeded by the PAH content of contaminated marine foodstuffs. Until other aromatic hydrocarbons, such as benzene, naphthalene, and anthracene, and/or their metabolic products, have been identified in edible marine animals, these constituents of petroleum should not be considered a human health hazard.[199,200,201]

B. <u>Natural Fluctuations</u>

It is now apparent that marine ecosystems undergo erratic long-term fluctuations, sometimes of considerable magnitude, from natural causes. This has been demonstrated in the recruitment of commercial fish species in the North Atlantic and North Sea, in the compositions of North Atlantic plankton, and in rocky coastline intertidal and benthic inshore sediments. Too few surveys have

been conducted long enough to reveal how widespread this phenomenon is, but it is expected to be significant, particularly in temperate marine environments. Some idea of the natural changes in the sedimentary benthos can be obtained from several publications.[202,203,204] Far less is known about natural fluctuations in subtidal rock communities.

The cause of these fluctuations is poorly understood, but appears to be related to climate. Increases in mean winter sea temperature of only 0.5°C between 1965-1970 and 1971-1976 were associated with a substantial change in species dominance in sediments off the northeast coast of England. This temperature change had little effect on the total production of the community, but the available energy was progressively transferred from one suite of species to another that clearly thrived better in the changed environment.[205]

Intertidal areas are even more exposed to climatic changes and can undergo dramatic alterations through a chain reaction. On a rocky shore in northeast England, equally suitable for limpets, barnacles, mussels, or seaweeds,[206] a heavy settlement of mussels destroyed all of the other species in 1967. Severe competition for space resulted in an unstable, hummocky development of the mussels, and they were swept away during storms in March 1968. The rocks were thus available for colonization by barnacles in June, but they and the limpets had been eliminated by the mussels in 1967. The destruction of the mussels occurred when young limpets could have recolonized the rocks. In the absence of these herbivores, diatoms and algae moved in, preventing the establishment of a barnacle population, and the area became temporarily dominated by seaweed.

A variety of climatic factors appear to influence the reproduction of limpets, and their survival newly settled on rocks and as adults.[207] Loss of adults or failure of the young to colonize permits the establishment of a dense covering of seaweed, thereby eliminating barnacles and inhibiting the re-establishment of limpets for several years.

Similar effects have been recorded for purely natural reasons. The mild winter of 1966-1967 allowed young dog whelks Thais to continue to feed and grow, so much so that they became too big to be eaten by the purple sandpiper, which normally controls their numbers. The large numbers of dog whelks ravaged the mussels on the beach, leaving space for colonization by barnacles, with a consequent change in the local ecosystem.[208] Reports of a number of similar examples show the critical importance of certain predators.

Natural fluctuations have the following important consequences for investigation and assessment of marine pollution:

- Even when a source of pollution is known, detailed and prolonged studies may be necessary to establish that it alone is causing a change in an ecosystem.

- Many pollution impact studies employ a neighboring unpolluted site as a control or reference point. However,

because natural fluctuations may be very local, the reference point may not be necessarily reliable for demonstrating pollution damage. The reliability of neighboring controlled areas is likely to depend upon local circumstances, which need very careful assessment.

- If the "normal" condition of an ecosystem is dynamic rather than static, post-pollution studies that measure recovery are faced with considerable uncertainty about when the ecosystem has returned to "normal" and recovery is complete.

Natural ecosystem fluctuation has been insufficiently appreciated in the past, and has undoubtedly led to erroneous conclusions.

C. Genetic Variability

There is growing evidence of high genetic variability in many marine organisms. Examples are known of genotypes that have quickly adapted to a particular set of local conditions.[209] It is suspected that a common tactic for survival in marine species may be the natural selection of viable genotypes, rather than individuals having wide tolerances of environmental conditions, which may explain the apparent contradiction between the results of laboratory toxicity tests (which tend to be conducted on genetically homogeneous animals) and natural events. Several strands of evidence support this conclusion:

- Genetic strains of a worm tolerant to petroleum hydrocarbons have been developed in the laboratory within five to ten generations, each generation lasting a few weeks.

- Some "opportunistic" species (e.g., *Capitella*) that rapidly colonize areas polluted by oil or other contaminants are genetically very variable and are now regarded as species complexes.

- Organisms inhabiting some polluted areas are genetically different from populations elsewhere. Sometimes this difference has been interpreted as evidence of pollution "damage," but may also reflect a natural adaptablity to a variety of environmental conditions.

A number of theoretical considerations arise from such observations. Species with highly dispersed larval stages will be able to evolve tolerant strains only if the area subject to pollution is considerably larger than the area of dispersion. Otherwise, subsequent generations will be recruited from outside the area of pollution and bring in "unselected" genotypes. The larval strategy is therefore an extremely important factor in determining whether locally selected genotypes will dominate or be swamped by wild genotypes from outside the polluted area.[210] This situation also yields hybrids that may be genetically dissimilar to both parents (cross-breeding).

D. Rare Species

Some organisms live at the fringe of their geographic range and have a precarious threshold. Their occurrence at particular sites may be sporadic, and slight changes in climate or sea temperature have a disproportionately great influence on their distributions.

If they are eliminated from a particular site by pollution (or from any other cause), their reappearance, once the source of disturbance is removed, is a matter of chance and may be slow. Conditions at the site may be only marginally suitable, or the next nearest population is at a distance. If a species is in fact receding (as with some sub-Arctic sea birds), lost fringe populations may not be restored at all.

E. Key Species

Marine ecosystems are determined initially by the nature of the substratum and by other physical factors. Nearly as important are interactions between a number of critical species. On intertidal rocks, herbivorous limpets graze down algae, so their presence or absence determines whether or not the shore is colonized by barnacles or by seaweeds and a rich associated fauna. In the sublittoral zone, sea urchins have the same dominating influence.

Carnivores that control the populations of dominant herbivores are equally important. The depletion of lobsters (through overfishing) on the Nova Scotia coast has been followed by an increase in the sea urchin population. These sea urchins overgraze the coastal algae, creating a "desert" and substantially reducing local production.[211]

F. Recovery from Pollution Damage

The severity of pollution damage depends less on its initial effects than on how long the pollution persists. As soon as the source is removed, recovery begins. For this reason, minor but chronic pollution is likely to cause progressive deterioration of the affected ecosystem and ultimately to be more damaging than an isolated pollution incident.

Recolonization of damaged areas is progressive. The first arrivals are hardy, "opportunistic" species, possibly with great genetic variability that include genotypes that survived in suboptimal conditions. Mobile species and those with short generation times and repetitive breeding also can recolonize such an area as soon as conditions are tolerable. Species that are relatively immobile depend upon their mobile larval stages to recolonize an impacted area. As most species breed seasonally, much depends upon when the pollution damage occurs. If there is a long interval between the damage and the availability of colonizing larvae, other species may have established themselves and will exclude newcomers.

Two aspects of recovery from pollution damage require dispassionate consideration. First, pollution (and sometimes the recovery processes) causes environmental change. There is a general

consensus that in some cases the change is harmful, but in other instances the issue is less well defined. Changes in species diversity, biomass, or biological production (common measures of pollution impact) all require careful interpretation against the background of natural fluctuation. Further, although change may be demonstrated, it is not invariably clear that it is necessarily for the worst.

Second, because marine ecosystems are fluctuating dynamic entities, recovery cannot be measured by a return to precisely the pre-damage situation. The few long-term studies conducted have shown that long-term natural fluctuations occur during the recovery period. Also, species that are rare and sporadic in their occurrence may or may not reappear, and it may be many years before the age structures of populations of organisms making up the community return to what they were prior to damage. From what we know of undamaged ecosystems, however, changes of this kind may be within the normal range of variability. It is more realistic to regard recovery as the restoration of a healthy, dynamic ecosystem, rather than the restoration of a status quo. Better understanding of these natural phenomena would bring greater realism to the assessment of pollution damage.

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CHAPTER SEVEN

ENERGY FACILITY SITING

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ENERGY FACILITY SITING

INTRODUCTION

I. Background

In many cases the requirements governing energy development have not yet been firmly defined. These requirements lengthen the lead time for planning of new, or expansion of existing, industrial facilities. The exact extent of additions to lead time varies widely from one case to another, depending upon which permit requirements apply to an individual case and what difficulties they present. For major expansions in any field of heavy industry, however, the delay resulting from federal requirements is likely to add one to three years to the lead time for the project. Moreover, in many cases there may be a possibility throughout the regulatory process that approval of the project will be denied.[1]

This chapter deals almost exclusively with environmental factors impacting facility siting. There are a number of other factors that may have an equal or greater impact on facility siting. Some of those other factors include problems such as finances, labor, material and equipment supply, transport, and non-environmental regulatory permits.

II. Laws and Regulations Applicable to Facility Siting

Government laws and regulations at all levels -- federal, state, and local -- have placed a number of constraints on all of the basic industries in the national economy. Table 78 identifies 16 major laws that constrain energy projects.[2]

The permitting process does not deal solely with environmental considerations, but environmental considerations have recently become more important than economic demands.[3] Several attempts have been made to predict the number of environmental permits required to develop an energy project. For example, the Department of Energy (DOE) has estimated that over 200 of the 400 permits required for an oil shale development project are directed to some type of environmental concern.[4] On the state level alone, for example, an energy project in Utah would require 69 permits: 16 exploration, 31 environmental, 12 municipal and county, and 10 special use.[5]

Table 79 represents in very general terms the number of permits, regulations, and clearances required by the federal government and one state, Colorado, as an example of state and local requirements.[6] Table 80 shows a simplified guide to federal permits.

TABLE 78

Major Laws and Regulations Constraining Energy Development

Clean Air Act, 42 U.S.C. 74-1 *et seq.*

Clean Water Act, 33 U.S.C. 1251 *et seq.*

Resource Conservation and Recovery Act, 42 U.S.C. 6901.

Coastal Zone Management Act, 16 U.S.C. 1451 *et seq.*

Federal Land Policy Management Act, 43 U.S.C. 1701 *et seq.*

Endangered Species Act, 16 U.S.C. 1536 *et seq.*

Antiquities Act, 16 U.S.C. 433.

Deepwater Ports Act, 33 U.S.C. 1501.

Outer Continental Shelf Lands Act, 43 U.S.C. 1331 *et seq.*

Wilderness Act, 16 U.S.C. 1131 *et seq.*

Safe Drinking Water Act, 42 U.S.C. 300f *et seq.*

Marine Protection, Research and Sanctuaries Act, 33 U.S.C. 1420 *et seq.*

National Environmental Policy Act, 42 U.S.C. 4321 *et seq.*

Alaska Native Claims Settlement Act, 43 U.S.C. 1601 *et seq.*

Surface Mining Control and Reclamation Act, 30 U.S.C. 1201 *et seq.*

Coal Leasing Amendments Act, 30 U.S.C. 201, 30 U.S.C. 1262, 30 U.S.C. 1272.

SOURCE: American Petroleum Institute, *Major Legislative and Regulatory Impediments to Conventional and Synthetic Fuel Energy Development*, March 1, 1980.

III. Environmental Impact Statements[7]

A. Federal EIS Requirements

Of all existing environmental requirements, perhaps the best known is the environmental impact statement (EIS). While this requirement has been debated throughout the 1970's, it has not evolved as a major factor in the approval of most major industrial projects other than power plants. Requirements to prepare an EIS do arise, however, in several cases involving petroleum projects.

TABLE 79

List of Permits (P), Regulations (R), and Clearances (C) Required by the Federal Government and the State of Colorado*

	Mines and Process	Roads
FEDERAL GOVERNMENT		
Department of the Interior		
Bureau of Indian Affairs	P	P
U.S. Geological Survey	P	C
Office of Surface Mining	P	
Bureau of Land Management	P	P
Bureau of Reclamation	P	P
National Park Service	C	P
Fish and Wildlife Service	C	C
Department of Agriculture		
Forest Service	P	P
Soil Conservation Service	C	C
Rural Electric Administration		
Environmental Protection Agency		
Water Quality	P	R
Air Quality	P	
	R	
	R	
	P	P
Federal Communications Commission	P	P
Interstate Commerce Commission		P
Mine Safety and Health Administration	R	
Department of Health	P	
Air Pollution Control Division	P	
Water Pollution Control Division	P	
State Historical Society	C	
Division of Highways	P	P
Highway Safety Division	R	R

STATE OF COLORADO (Continued)		
Department of Natural Resources		
Division of Water Resources (State Engineer)		
Geological Survey		
Co. Groundwater Commission		
State Board of Land Commissioners		
Division of Mines		
Oil and Gas Conservation Board		
Mined Land Reclamation Section		
Co. Soil Conservation Board		
Co. Water Conservation Board		
Division of Wildlife		
Division of Parks and Recreation		
Public Utilities Commission		
Land Use Commission		C
<u>Colorado Local Governments</u>		
County		
Land Use		
Air Quality		
Water Quality		
Health		
Fire		
Flood		
Building Codes		
Roads	R	R
Municipal and Special Districts		
Land Use		P
Air Quality		
Water		
Sanitation		
Health		
Fire		
Flood		
Building Codes		
Streets		P

*For coastal states there is the additional requirement to comply with Coastal Zone Commission regulations, which require that all federally issued permits be consistent with the state's coastal zone plan.

SOURCE: Colorado School of Mines, Permits Handbook for Coal Development, 1980.

	Permit	Statute	Regulation	Agency
Leasing	BLM Coal Lease	Mineral Leasing Act of 1920. 30 USC 181 Fed. Coal Leasing Amendments Act of 1976 30 USC 201 P.L. 94-377	BLM Regs on Management of Federal Coal 43 CFR Part 3400	Bureau of Land Management (BLM)
Exploration	Coal Exploration Permit	Mineral Leasing Act of 1920. 30 USC 181 Fed. Coal Leasing Amendments Act of 1976 30 USC 201 P.L. 94-377	BLM Reg. on Coal Leasing 40 CFR Part 3410	BLM, U.S. Geological Survey (USGS), Office of Surface Mining (OSM)
Mining	Mine Plan, Mining and Reclamation Permit	Surface Mining Control and Reclamation Act/1977 30 USC 1201 P.L. 95-87	OSM Permanent Regulatory Program 30 CFR Parts 700-899	OSM
Environmental Impact	Environmental Impact Statement	National Environmental Policy Act 42 USC 4321 P.L. 91-190	CEQ Regs on implementing NEPA Procedures 40 CFR Part 1500	Federal Lead Agency (may be OSM, BLM or EPA)
Air	Prevention of Significant Deterioration (PSD)	Clean Air Act Amendments of 1977 42 USC 7401 P.L. 95-95	EPA PSD Regs 40 CFR Part 52 & EPA Consolidated Permit Regulations 40 CFR Parts 122-124	Environmental Protection Agency (EPA)
Water: NPDES	National Pollutant Discharge Elimination System	Clean Water Act 33 USC 1251 P.L. 95-217	EPA Consolidated Permits Regulations 40 CFR Parts 122-124	EPA
Water: Dredge & Fill	Dredge and Fill Permit (404)	Clean Water of 1977 33 USC 1251 P.L. 95-217	Army Corps of Engineers Regulatory Program 33 CFR Part 320 EPA Regs on Dredge & Fill Activities 40 CFR Part 230	Army Corps of Engineers and EPA
Water: Public Water Supply Systems	Plan Review	Safe Drinking Water Act P.L. 95-190 42 USC 300(f)	National Interim Primary Drinking Water Regulations 40 CFR Part 141	EPA
Water: Underground Injection Control (UIC)	Underground Injection Control Permit	Safe Drinking Water Act P.L. 95-190 42 USC 300(f)	EPA Consolidated Permit Regulations 40 CFR Parts 122-126	EPA
Hazardous Wastes	Permit for Generators, Transporters, or Disposers of Hazardous Wastes	Resource Conservation and Recovery Act of 1976 42 USC 6901 P.L. 94-580	EPA Regs on Hazardous Waste Management Systems 40 CFR Part 260 and EPA Consolidated Permits Regulations 40 CFR Parts 122-124	EPA
Toxics	Compliance with Prohibitions, Recordkeeping, etc.	Toxic Substances Control Act 15 USC 2601 P.L. 94-469	Final PCB Prohibition 40 CFR Part 761 Recordkeeping & Reporting 40 CFR 712	EPA
Coordination	Consolidated Permits Program	Authorized by the 4 statutes involved: Clean Air Act/1977 42 USC 7401; Clean Water Act/1977 33 USC 1251; Safe Drinking Water Act 42 USC 300(f); Resource Conservation & Recovery Act 42 USC 6901	EPA Consolidated Permits Regulation 40 CFR Part 122-124	EPA

*All United States Code (USC) citations are to Sections. All Code of Federal Regulation (CFR) citations are to Parts.

SOURCE: Colorado School of Mines, Permits Handbook for Coal Development, 1980.

The National Environmental Policy Act (NEPA) became law on January 1, 1970. Section 102(2)(c) of that statute requires all agencies of the federal government to prepare detailed EISs on proposals for legislation and other major federal actions significantly affecting the quality of the human environment. The purposes of this provision are to include in the agency decision-making process careful consideration of all environmental effects of proposed actions and to explain the potential environmental effects of those actions and their alternatives to the public. General responsibility for administering these requirements rests with the Council on Environmental Quality (CEQ), and each federal agency is responsible for preparing impact statements on its own actions. Court decisions have made it clear that such actions include the issuance of licenses or permits to private parties for the construction of projects that would significantly affect the environment.

None of the federal actions under the Clean Air Act trigger an EIS requirement. When the Energy Supply and Coordination Act was enacted in 1974, it amended various provisions of the Clean Air Act, and one of those changes excluded EPA's actions under the Clean Air Act from NEPA. Actions requiring a company to use coal were not exempted from NEPA by that statute, but the Powerplant and Industrial Fuel Use Act of 1978 does exempt actions by DOE requiring new plants to use coal. By contrast, the Resource Conservation and Recovery Act of 1976 (RCRA) does not exclude from NEPA its program activities, including the issuance of permits for hazardous waste disposal facilities. Thus a company seeking to obtain a RCRA permit from EPA would be exposed to an EIS requirement if approval

of its facility is considered to meet the "major federal action" test. When state agencies assume responsibility for issuance of RCRA permits, however, their approval of a facility presumably would not be considered to involve any federal action, and thus no EIS under NEPA would be required.

The issuance of dredge and fill permits by the U.S. Army Corps of Engineers is subject to NEPA In the case of the Coastal Zone Management Act, there is no statutory exclusion, and extensive EISs are prepared for each state program as it is submitted for approval by the Secretary of Commerce. Approval of individual industrial projects under the Coastal Zone Management (CZM) programs, however, would be an action by the responsible state agencies and hence would not be subject to the federal EIS requirements.

B. State EIS Requirements

Many states have adopted laws or regulations similar to NEPA requiring state environmental impact reports or statements. The states where such requirements have been established are listed below.

- ● California
- ● Connecticut
- Hawaii
- Indiana
- ● Maryland
- Massachusetts
- Michigan
- ● Minnesota
- ● Montana
- New Jersey
- New York
- North Carolina
- South Dakota
- Texas
- Utah
- Virginia
- Washington
- Wisconsin.

IV. Project Planning and Decision-Making

The federal regulations applicable to industrial projects clearly present a challenge to the traditional practices of corporate decision-making, management, and long-range planning. Those responsible for new plants must develop a fresh approach to the planning and management of industrial expansion.

A. Regulatory Uncertainties and Project Lead Time

The biggest regulatory uncertainty is the actual extent of delay that the regulations impose on the functioning of the economy. It is possible to identify a number of cases where the difficulty of obtaining environmental approval for a new plant was not anticipated by the company. One widely publicized example involved the petrochemical facility the Dow Chemical Company undertook to build a few miles east of San Francisco, only to abandon the project due to environmental difficulties after an investment exceeding $6 million. In numerous other cases, including several proposed oil refineries, companies have been blocked for several years in their attempts to locate a major new facility. In the construction of new electric power plants, lengthy delays have become common, occasionally ending in the abandonment of a project.[8]

The expected one to three years' lead time that may be required to meet all regulations for major projects varies from case to case. It depends upon the type of environmental problems presented by a particular project, the success of the company in gathering all of the data called for to meet government requirements, the level of cooperation established between the corporate and government officials, and the overall political acceptability of the project in the surrounding community.

Even with the best foresight, the regulatory process adds to the lead time for a project. To obtain data needed for several of the environmental reviews it is now necessary to complete rather detailed engineering plans at an early stage in the project planning schedule. At the same time, actual construction cannot begin until many of the requisite approvals are obtained. As a result, most of the regulatory compliance must take place between the completion of engineering plans and the commencement of construction, which would otherwise be a narrow time gap or even an overlap.

Many of the environmental approvals can be obtained, at least theoretically, within several months after an acceptable application has been submitted. For others, the total time consumed will be measured not in months, but in years. For any large industrial project, such as a new oil refinery, petrochemical complex, or oil shale project, the acquisition of required approvals is likely to require one to three years.

The riskiness of an investment in a new plant may also vary from place to place, influencing firms' investment behavior. For a given level of compliance costs, a firm may find that one state offers a speedier decision-making process and a greater assurance of project approval than another state. Significant variations in business climate exist among the states.

B. New Grassroot Site vs. Expansion of Existing Site

In general, the obstacles to approval of new plants are greater than for expansion of existing plants, and thus most companies will be encouraged to expand their current facilities rather than to build new "grassroots" plants. The delays and difficulties affecting approval of any expansion will also provide an incentive to continue operating existing facilities beyond their normal lifespan, which conserves capital and all but eliminates land-use conflicts. Yet it carries the risk that production costs will slowly rise as equipment gets older and downtime increases, as well as the possibility that the firm will eventually lose technological leadership to its domestic or foreign competitors.[9]

Among the most important federal standards that vary with location are several imposed under authority of the Clean Air Act and its 1977 amendments. First is the requirement that new or expanded plants in nonattainment areas must utilize Lowest Achievable Emission Rate (LAER), obtain offsets, and ensure that all

other sources in the state owned by the proposed new source owner are in compliance with all applicable rules. Thus, plants within such areas must comply with a requirement not imposed on plants located elsewhere. Moreover, emission offsets are more easily obtained in some places than in others. For example, some of the fast-growing "Sunbelt" cities, such as Houston, Dallas, or Tulsa, may not have as many old, higher polluting facilities that can provide offsets as some of the older industrial cities. Offsets are also relatively difficult to obtain in places such as Los Angeles and San Francisco, where stationary sources have long been subject to stringent state pollution controls.

Another important Clean Air Act requirement governs the construction of large new potential pollution sources in areas that do meet federal air quality standards. Particularly strict Prevention of Significant Deterioration (PSD) controls have been imposed by Congress in order to protect air quality and visibility in and around approximately 160 specified national parks and monuments.[10] Under the PSD regulations, all other areas of the country were placed in the Class II category. Class II areas allow moderate growth limited by the amount of air quality increment remaining in each area. After an increment is exhausted, no large new sources will be allowed unless the state plan provides for growth through tighter controls or offsets. Class I areas are essentially off limits to major development projects because the allowable PSD increment is too small.

Although most discussions of industrial siting tend to emphasize federal pollution controls, the importance of state and local land-use controls, including ad hoc controls imposed as a result of citizen objections to projects, must not be neglected. For example, of 12 proposed East Coast oil refineries cancelled on environmental grounds between 1970 and 1974 by state/local action, at least nine were denied because of inability to secure zoning or by local referendum, not because of failure to secure environmental permits.[11]

Even in cases in which regulatory standards are uniform nationwide, there may be state or regional differences in interpretation or in enforcement. Some federal laws ostensibly imposing uniform standards in fact allow state and regional administrators a great deal of leeway for interpretation and negotiation with applicants. For example, offsets in nonattainment areas may be barely one-for-one or may involve (as in California's Sohio PACTEX pipeline case) offsets several times as great as the pollution to be generated by the new plant.

Although new plants in many pollution-intensive industries must meet uniform national New Source Performance Standards (NSPS), the required determination that a plant locating in a PSD area is using Best Available Control Technology (BACT) is negotiated between the EPA region and the firm. The possibility of inconsistent interpretation may well increase after states, as is expected, take over PSD permitting administration.

It has been charged occasionally that pollution controls affect the size of plants that are built. For example, while a very large oil refinery project on the East Coast was waiting to obtain its permit, at least 13 small [less than 30 thousand barrels per day (MB/D)] refineries were built in Louisiana alone. These projects were located in PSD areas, but several did not need to obtain PSD permits because they claimed their emissions of any single pollutant would be less than 100 tons per year.

Other environmental standards may have indirect impacts on the relative attractiveness of various industrial locations. For example, a former EPA administrator told the National Governors' Conference that industry will look for states that have federally approved hazardous waste disposal facilities.[12]

An important consideration is whether allowing states or localities so much power over siting decisions is consistent with national interests. For example, the refusal of coastal jurisdictions on the East Coast to accept oil refineries has implications for the entire regional supply of energy. The question is whether such decisions should be made by small towns such as Durham, New Hampshire (which voted down a large refinery in 1974), or by a level of government with greater geographic scope; or similarly, whether a jurisdiction in the Ohio Valley should be allowed to accept a great deal of industrial pollution (in exchange for high-wage jobs for local people) when the air and water pollution generated drifts across jurisdictional borders and affects people who live elsewhere. The desire to protect assets of recognized national value from the impact of local decisions to accept new industry led to the mandatory designation by Congress in 1977 of many national parks and monuments as Class I PSD areas.

Another important consideration is the impact of environmental controls on business risk. In traditional investment theory, a firm balances the rate of return expected from an investment against the risk involved. Delay of projects and uncertainty of outcome are two frequent accompaniments of environmental regulation. Both increase business risk. To what extent does this increased risk reduce the rate of new investment? This question is extremely important in this era of national concern over low rates of capital formation, lagging industrial innovation, and the international competitiveness of American industry.

C. Scoping the Project

Initial screening should be undertaken early in the planning process to identify possible environmental difficulties. Such a review should highlight major issues, identify significant additional project costs, itemize data required for permit applications, approximate lead times, and formulate contingencies (e.g., alternate sites, alternate control technologies, or changes in overall design).

The initial project plan should specify the environmental risks. These risks include early disclosure of the company's

The concept of identifying acceptable sites for industry is embodied in recent federal coastal zone legislation. Before state CZM plans can be approved, they must identify sites of unique geologic or topographic importance to industrial development and ensure that facilities of greater than local concern are not arbitrarily or unreasonably excluded or restricted.

There have been a number of initiatives that would go even further. Best known, perhaps, is the 1978 American Bar Association (ABA) report, Development and the Environment: Legal Reforms to Facilitate Industrial Site Selection, which suggested that states develop comprehensive plans to identify "particular areas best suited for particular types of industrial development." While its recommendations generated a great deal of interest and comment, the report was never formally approved by the ABA, and to date no state has adopted a comprehensive statewide plan delineating specific sites where certain industries might be located.

One state, however, has embraced the idea of advanced site identification and banking, but only with respect to power plants. Pursuant to the Maryland Power Plant Siting Act of 1971, the Maryland State Power Commission has authority to purchase sites around the state and hold them for future power plant development. The operation is financed by a small surcharge on utility bills. The state believes that the siting certainty of this system will avoid unnecessary delay and higher construction costs. In practice, though, this system has encountered difficulties. Due to a combination of factors, e.g., local government and citizen opposition, and decreasing demand for new plants, only one site has been acquired and it stands vacant.

Questions have also been raised about the applicability of the system to industries on a wider basis. Many are skeptical that the federal or state governments are sufficiently knowledgeable to select sites suitable for industrial growth or whether such activity is proper in a free market economic system. Others question whether it is beneficial, in terms of time and money, to approve a site for development before a specific proposal is made by an industry, or whether environmental considerations can be adequately evaluated before the regulators know what will be built.

These questions and concerns are troublesome, but this option should not be summarily discarded. If environmental controversies over large facilities continue, pre-site identification and approval and even public site banking may become more appealing.

U.S. Steel tried an innovative planning effort for a massive new 4,000-acre steel plant in Conneaut, Ohio, which may serve as a model for future large-scale industrial development. That effort, monitored by the Department of Commerce's early corporate environmental assessment program, was premised on the twin obligation of corporations to initiate environmental assessments early in the project review process and of the federal government to assume a lead agency management approach to its environmental assessment

responsibilities. U.S. Steel was not guaranteed that needed permits would be issued, but by eliminating overlapping reviews and multiple hearings, a final EIS was produced in only 24 months. The Department of Commerce is publicizing the U.S. Steel experience in the hopes that it will persuade other corporations that early disclosure of project plans and timely environmental impact analysis will help the project in the long run.

In some instances, a Conneaut-size industrial project can overwhelm the evaluative capability of states, especially small states and local governments that suffer from limited resources and lack the tools for sophisticated analysis. This problem is most acute in the context of energy- or mineral-related projects, especially in the West, but appears to be spreading.

The multiple permit problem has received a good deal of attention during the past decade. The previously discussed ABA industrial siting report recommended the creation of a superagency at the state level to oversee siting of large-scale industrial complexes of greater than local concern, with powers to issue all permits and override local zoning where necessary. Several jurisdictions (Wyoming, Washington, and Forida) adopted such legislation, but the results have been mixed.

The Florida Electrical Power Plant Siting Act, which pre-empts to the Governor and his cabinet regulation at the state level of the construction and operation of power plants, appears to be working better than similar legislation in other states. Developers elsewhere often discovered that the expected simplification of the process was an illusion. For example, in Wyoming, where a seven-member industrial siting council to review proposed industrial development costing in excess of $50 million, an applicant must obtain environmental and land-use permits from other state and local agencies before applying to the state siting council for permission to develop. In effect, the siting act adds another level of bureaucracy. In Washington, which has a voluntary permit coordination mechanism administered by the State Department of Ecology, the experience is similar. Many project developers have elected to seek permits individually rather than through the system's consolidated proceedings because the coordinated procedure may take longer than individual applications to each agency.

Local jurisdictions often oppose permit coordination, in some cases viewing such efforts as power plays by state or regional agencies. The result in many instances is that local regulations, particularly land-use laws, are not brought within the statewide permit coordination system. In the state of Washington, local governments opposed the first draft of the Environmental Procedures Act, which would have included local permits, and worked successfully to have that aspect of the legislation dropped. Ironically, one of the continuing problems with the Act has been that developers cannot begin the state-coordinated permitting process until local governments grant necessary approvals.

The federal government has made several attempts to improve the siting process for major facilities. In 1978, the President signed

an executive order to provide for timely, coordinated federal decisions on critical non-nuclear energy facility permit applications. The order directs the Office of Management and Budget to organize a system to expedite multiple agency reviews and establish deadlines for final administrative decision-making by eight federal agencies.

These federal, state, and local coordination efforts may provide some relief to industry, but they do little to improve coordination within various levels of government. The easing of the permitting burden at the national level by the federal government will not accomplish a great deal if a local zoning authority opposes the project.

Colorado has developed an innovative approach to the problem of interagency coordination. Colorado's Joint Review Process for Major Energy and Mineral Resource Development Projects (JRP) is an intergovernmental review process that coordinates the government's review of major energy and mineral resource development projects that are in early stages of project planning development.[14] Using Colorado's JRP as a guide, several states are developing similar review processes.

The JRP coordinates regulatory and administrative reviews conducted by the three levels of government, thus expediting those review processes and improving the quality of project planning and review. It provides the public and industry with increased opportunity to become involved with government in the review of a project. Participation in the JRP is voluntary; its success depends upon a high level of communication, cooperation, and compromise. The JRP is not a new regulatory program and does not establish new regulatory bureaucracy. It is not an attempt to create an energy facility siting procedure or other new decision-making authority.

V. Specific Examples of Delayed, Denied, or Abandoned Energy Projects[15]

The petroleum industry is concerned about the cumulative impact of all of the environmental and other laws that regulate energy development. Following are specific examples of energy projects delayed or cancelled because of governmental constraints of many kinds

- Santa Ynez Unit, California Outer Continental Shelf; 27 MB/D of oil and 30 million cubic feet of natural gas per day. The project was delayed for seven years by federal, state, and local regulatory obstacles. There were three major environmental impact studies, 21 major public hearings, 10 major government approvals, 51 consultant studies, and 12 lawsuits involving the project, some initiated by the project. After an investment of more than $380 million, the project finally began producing oil in April 1981.

- PACTEX, Sohio marine terminal and pipeline, Long Beach, California, to Midland, Texas; 500 MB/D. This pipeline was intended to carry Alaskan crude oil to Midland, Texas, and then to the Midwest. The project was cancelled after it became uneconomic following a five-year delay in obtaining the necessary federal, state, and local air quality permits.

- Hampton Roads Energy Company oil refinery, Portsmouth, Virginia; 170 MB/D. An eight-year delay was caused in large part by needed EPA approval of the State Implementation Plan under the Clean Air Act and needed dredge and fill permit from the Corps of Engineers. The project was cancelled in part due to the decreased need for refinery capacity by the time the permit was obtained.

- Pittston oil refinery, Eastport, Maine; 250 MB/D. The project has been delayed because EPA, to protect the habitat of the bald eagle, declined to issue a water pollution discharge permit.

- Seadock deepsea port, 31 miles south-southeast of Freeport, Texas; ability to receive tankers to 700,000 deadweight tons, with unloading rates up to 150,000 barrels per hour. Cancellation of the project occurred after excessive licensing restrictions forced participants to withdraw.

- Enhanced oil production, Kern County, California. Delays caused by failure of EPA and the California Air Resources Board to issue necessary permits for steam generators in the late 1970's restricted production by nearly 200 MB/D. If additional Clean Air Act restrictions were removed, heavy oil production could increase by 350 MB/D.

- Georges Bank Marine Sanctuary proposal. The Conservation Law Foundation nominated the entire Georges Bank fishery as a sanctuary -- a total of 20,000 square miles encompassing the North Atlantic OCS Lease Sale area. This nomination was submitted to delay Lease Sale #42 in mid-1979 and to reserve the Georges Bank area. The fishery was placed on the list of areas that could possibly be designated a marine sanctuary.

- Oil and gas production, Bastian Bay, Louisiana; 828,000 barrels of oil and 2.9 billion cubic feet of natural gas reserves. A delay of 153 days occurred before the Federal Energy Regulatory Commission granted a permit to build a gas pipeline from an offshore platform.

- Oil production, West Hastings Field, Texas; 4 MB/D. Requirements of the Texas Air Control Board and EPA have prevented the use of gas-lift compressors since late 1978.

- Oil production, Cat Canyon Field, California. Two steam generators were shut down due to tight natural gas supplies.

This resulted in a decrease in the production of crude oil. An application was made to the California Air Pollution Control District for Santa Barbara County requesting permission to use crude oil for fuel. The district would not grant a permit unless the company hired an outside consultant to prepare an EIS. The resultant delay was estimated to be six to eight months.

- Oil production, USA #1-a, Perry County, Mississippi. Normal procedures were followed to obtain approval for drilling an exploratory well. After drilling, control problems were encountered and the well had to be abandoned. The company wanted to drill an identical well only 50 feet from the first one. The permitting agency decided that doing so would require repetition of the entire permitting process and completion of another environmental assessment. It is estimated that this requirement delayed the project five months.

- Offshore oil and gas production, Block 104, East Cameron, Louisiana. Requests for permits to drill were filed in late 1978, but were not awarded until mid-May 1979.

- Offshore oil and gas production, Block 687, Matagorda Island off Texas. An exploration plan was filed with the appropriate regulatory agencies in April 1978. The company did not obtain approval until January 1979. The delay stemmed primarily from the U.S. Fish and Wildlife Service's concern that boats and helicopters passing through the intercoastal waterway to and from the drilling rig would disturb the winter nesting grounds of whooping cranes located in the Aransas National Wildlife Refuge. It has been demonstrated that this is not the case.

- Offshore oil and gas production, Block 912, off Georgia. This tract was purchased at the federal lease sale held March 28, 1978. Requests for permits were sent to the U.S. Army Corps of Engineers on May 26, to EPA on June 12, and to the U.S. Geological Survey (USGS) on December 27. The well permit was not granted until May 16, 1979, almost one year after the first requests were submitted.

- Offshore oil and gas production, Block 139, South Marsh Island, Gulf of Mexico. This tract was purchased at the federal lease sale held December 19, 1978. Requests for a drilling permit were sent to EPA on February 26, 1979, and to the USGS on March 9. The well permit was received on July 12, 1979, approximately five months after it was requested.

- Offshore oil and gas production, Santa Barbara Channel, California. After the 1969 Santa Barbara oil spill, the USGS imposed a moratorium on construction of all additional platforms in the area while it studied the cause of the spill. Installation of Platform Henry was delayed approximately 11 years before the USGS finally approved the third development plan.

INDUSTRY EXPERIENCE

I. Exploration and Production

A. Offshore Case Study No. 1: Platform Gina and Platform Gilda Project

Union Oil Company of California proposed to develop a federal Outer Continental Shelf (OCS) lease in the Hueneme Field and the Santa Clara Unit offshore Ventura County, California. The proposed project, designated the Platform Gina and Platform Gilda Project, included two production platforms, pipelines to shore, an onshore treating facility, and product/crude oil/natural gas pipelines that would connect the treating facility to existing distribution systems. Examined in this section are the applicable regulations, legislation, and permits to this offshore energy project (see Table 81), as well as the regulatory and permitting delays. Table 82 lists the possible environmental impacts resulting from this type of facility. In nearly all activities the environmental impact is of minor or low significance.

Several roadblocks to this exploration and development project were encountered as a result of the delay in the preparation of the environmental impact report/environmental assessment. The project slowdown was due to the complexity in the development of the document caused by overlapping jurisdiction (federal, state, and local) and by limited communications between the agencies, which led to a six- to 12-month regulatory delay for the Gina/Gilda Project.

B. Offshore Case Study No. 2: The Santa Ynez Unit

1. Historical Background

The Santa Ynez Unit is composed of federal leases on the OCS near Santa Barbara County, California. Water depths in the Santa Barbara Channel range up to 2,000 feet. In anticipation of a sale involving such deepwater tracts, Exxon had devoted large amounts of capital to perfect the deepwater technology required for such operations. These technologies involved floating drilling technology, extension of the use of platforms to very deep water, and an entirely new concept using a totally submerged production system.

Exxon acquired its interest in these and other leases in the Santa Barbara Channel for $218 million in early 1968. After the leases were acquired, 50 exploratory wells were drilled in the Santa Barbara Channel, several of which set world records for deepwater drilling. Three oil and gas discoveries were made in the western end of the Channel -- the Hondo field in 1969 and the Pescado and Sacate Fields in 1970. In late 1970, the federal government approved the formation of the Santa Ynez Unit, consisting of 17 leases encompassing these three fields. The three fields are located in water depths ranging from 600 to 1,200 feet, deeper by far than any previous development anywhere in the world. The crude oil to be found there is high in sulfur content and for the most part is located in a very dense chert formation. This complex

TABLE 81

Legislative and Regulatory Permits Required for Platforms Gina and Gilda

Reviewing Agency	Permit, Lease, or Approval Required	Applicable Project
City of Oxnard, Planning Department	Amendment to General Plan	Mandalay East Mandalay
	Special Use Permit	Mandalay East Mandalay Ormond Beach
	Zone Change Application	Mandalay
	Parcel Map	Mandalay East Mandalay Ormond Beach
City of San Buenaventura, Planning Department	Amendment to General Plan	Union Oil Marine Terminal
	Conditional Use Permit	Union Oil Marine Terminal
	Zone Change Application	Union Oil Marine Terminal
County of Ventura, Planning Department	Modification to Existing Conditional Use Permit	Union Oil Marine Terminal
County of Ventura, Planning Department	Watercourse Encroachment Permit	Onshore Pipelines for Union Oil Marine Terminal, or Ormond Beach
County of Ventura, Local Agency Formation Commission	Annexation to City or Water District	All Onshore Sites
Port Hueneme, Oxnard Harbor District	Easement Permit	Onshore Pipelines Ormond Beach
County of Ventura, Property Administration Agency	Land Lease Permit	Mandalay
County of Ventura, Air Pollution Control District	Permit Authority to Construct and Operate	All Onshore Sites

TABLE 81 (Continued)

Reviewing Agency	Permit, Lease, or Approval Required	Applicable Project
California Coastal Commission	Coastal Development Permit	Offshore Pipelines All Onshore Elements
	Federal Consistency Certification	Overall Project Review
State Lands Commission	Lease of Pipeline Right of Way	All Offshore Pipelines
State Department of Fish and Game	Stream Alternation Permit	Onshore Pipeline for Union Oil Marine Terminal, or Ormond Beach
State Department of Boatings and Waterways	Comments Only	
State Department of Parks and Recreation	Comments Only	
California Regional Water Quality Control Board	Trenching Permit	All Offshore Pipelines
	Hydrostatic Test Permit	All Offshore Pipelines
U.S. Army Corps of Engineers	Platform Structure Permit	Gina and Gilda
	Section 404 Permit	Offshore Pipelines
U.S. Coast Guard	Navigational Aids Approval	Sights and Sounds on Both Offshore Platforms
U.S. Geological Survey	Plan of Development Approval	Gina and Gilda
	Air Quality Permit	Gina and Gilda
State Water Resources Control Board	Federal Consistency Certification	All Offshore Pipelines
U.S. Environmental Protection Agency	Prevention of Significant Deterioration (PSD) Permit	All Onshore Sites
	National Pollution Discharge Elimination System (NPDES) Permit	Offshore Pipelines and Platforms

TABLE 82

Possible Environmental Impacts from Platforms Gina and Gilda

Environmental Factor	Activity	Nature of Impact	Significance*
Air Quality	Construction	Minor increases offshore in emissions of NO_x, SO_2, CO, HC, and particulates	L
	Drilling	Minor increases in emissions of NO_x, CO, SO_2, HC, and particulates	L
	Production	Minor increases onshore and offshore in emissions of NO_x, SO_2, CO, HC, and particulates	L
Water Quality	Construction	Localized minor increases in turbidity	L
		Localized minor alteration of ocean water quality resulting from discharges	L
	Drilling	Localized minor increases in turbidity	
		Localized minor alteration of ocean water quality resulting from discharges	L
	Production	Localized minor attentions of water quality resulting from discharges, and leachings of metals	L
		Negligible water temperature alternation caused by heat dissipation from offshore pipelines	L
Land Impacts	Construction	Localized minor alteration of topography	L
		Localized minor disturbance of soils	L

TABLE 82 (Continued)

Environmental Factor	Activity	Nature of Impact	Significance*
Land Impacts (Continued)	Construction	Localized minor disturbances in beach/near-shore crews	L
		Elimination of sedimentary habitat (210,000 ft^2) and associated marine organisms	L
		Localized minor alteration of phytoplankton productivity	L
		Entrainment of zooplankton (6,500 lbs)	L
		Temporary loss of commercial fishing area	L
		Removal of vegetation and temporary or permanent loss of following habitats fore-dune, dune scrub, ruderal, and urban	L
		Displacement or elimination of individuals of the animal species associated with the disturbed habitats	L
	Drilling	Increase in biomass and species diversity near platform	L-M
		Elimination of sedimentary habitat (83,000 ft^2) and associated marine organisms beneath cuttings mounds near platforms	L
		Localized minor alteration of phytoplankton productivity	L
		Possible effects on marine animals from presence of platforms, increased noise, and human activity	L
	Production	Increased biomass and species diversity related to new substrate	L-M

TABLE 82 (Continued)

Environmental Factor	Activity	Nature of Impact	Significance*
Land Impacts (Continued)	Production	Localized minor alteration of phytoplankton productivity	L
		Consumptive use of fresh water	L
		Temporary interference with local land uses	L
		Minor temporary interference with recreational activities	
		Short-term increased traffic volumes on the local road system	L
	Drilling	Minor alteration of seafloor topography resulting from formation of cuttings mounds at the two platforms	
		Consumptive use of fresh water (44.1 acre-feet)	
		Minor increases in traffic volumes on the local road system	L
	Production		
			L
		Consumptive use of fresh water (9.4 acre-feet)	L
		Commitment of land to industrial use	L
		Negligible increases in traffic volumes on the local road system	L
Ecological Impacts	Construction	Temporary disturbances of sedimentary habitat and associated marine oraganisms (320,000 ft^2)	L

TABLE 82 (Continued)

Environmental Factor	Activity	Nature of Impact	Significance*
Ecological Impacts (Continued)	Construction	Entrainment of zooplankton (1,300 lbs/day) for 3-year period at Platform Gina related to seawater intake for reservoir pressure maintenance program	L
		Loss of potential commercial fishing area; possible effects on marine mammals due to noise, increased activity, and presence of platforms	L
Aesthetic Impacts	Construction	Localized sound level increases at offshore and onshore locations	L
		Temporary visual intrusion affecting offsite viewers	L-M
	Drilling	Localized sound level increases at the two platforms	L
		Visual intrusion of two platforms	L-M
	Production	Localized sound level, increases at offshore and onshore locations	L-M
		Visual intrusion of onshore treating facilities and two platforms	L-M
Socio-economics	Construction	Minor increased demand for transient housing, services, and utilities	L
		Minor increase in employment opportunities	L

TABLE 82 (Continued)

Environmental Factor	Activity	Nature of Impact	Significance*
Socio-economics (Continued)	Construction	Increased sales and use taxes accruing to local governments and to the state	L-M
		New local taxable retail sales	L
	Drilling	Negligible to minor increased demand for transient housing, services, and utilities	L
		Negligible increases in employment opportunities	L
		Increased sales and use taxes (local and state)	M
		New taxable retail sales to local government	M
	Production	Negligible to minor increased demand on housing, services, and utilities	
		Negligible increase in employment opportunities	L
		New property tax revenue	L
		Sales and use tax revenue accruing to local and state governments	L
		New taxable retail sales to local government	L
		New royalty payments to U.S. government	
Cultural	Construction	Possible disturbance of an onshore ethnographic site, and three potential offshore shipwreck locations	L

TABLE 82 (Continued)

Environmental Factor	Activity	Nature of Impact	Significance*
Accidents	Drilling	Accidental oil spills could have effects on various environmental resources and uses. The magnitude of effects depends on spill size, location, and time of year	L-H
	Production	Same as above	L-H

*L = low; M = medium; H = high.

situation carries with it more than the normal uncertainties involved in estimating reserves and predicting future production.

Based on 29 exploratory wells drilled within the Santa Ynez Unit area, the most significant reserves appeared to be in the Hondo Field. Even though there was considerable economic risk associated with this deepwater development, particularly with the relatively poor crude oil and reservoir properties, Exxon decided to undertake very large expenditures in the Hondo Field.

In early 1971, a Plan of Operations for initial development of Hondo was submitted to the USGS. Exxon expected that the plan would be approved in about six months and that production could begin in early 1974. This timing was in keeping with Exxon's experience in the Gulf of Mexico and with that of other operators in the Santa Barbara Channel. Extensive regulatory delays were encountered, however. As a result, production start-up could not be accurately forecast.

2. Federal Plan Approval

Following submittal of the Plan of Operations in early 1971, the USGS determined that a more detailed plan was required. The final plan, when supplemented by a seven-volume report later in 1971, was the most extensive ever filed by an operator of a federal lease. Based on this material, an 1,800-page federal EIS was prepared by the USGS. This was the first EIS ever prepared for an OCS development. Public hearings were held for three days in Santa Barbara. The final EIS was issued in May 1974.

In August 1974, after more than three years of study, the Secretary of the Interior approved the Plan of Operations. Two

alternatives for treating and transporting the produced oil were recommended. The preferred plan provided for treating the oil onshore and then moving it to market by tanker using an existing but modernized marine terminal. However, the Secretary recognized that difficulties could be encountered in securing the necessary local consents. In order to assure timely development of this domestic energy reserve, he also approved a floating offshore storage and treating (OS&T) facility with tanker loading facilities to be moored in federal waters. No serious objections to the Plan of Operations were voiced by the State of California during the entire plan review process. In fact, the State Lands Commission adopted the federal EIS as its own report during proceedings that led to the granting of a pipeline and marine terminal lease.

3. Initial Development Plan (Onshore)

Even before federal approval of the plan, Exxon began efforts to secure necessary local permits. Following an extensive County-prepared environmental impact report, the onshore treating facility and marine terminal were approved by the Santa Barbara County Planning Commission and the Board of Supervisors. In May 1975, they were approved by voters in a referendum.

Following this referendum, Exxon applied to the South Central Region Coastal Commission for a permit for the portion of the pipeline and marine terminal that would be in the Coastal Zone. During the course of those proceedings, opponents of the project recommended deletion of the marine terminal portion of the onshore facilities in favor of pipeline transportation. The question of pipeline transportation had been considered by the federal EIS and rejected because a pipeline had no environmental advantage and a substantial economic disadvantage compared to using tankers.

The Regional Commission considered the pipeline alternative, rejected it, and in September 1975 issued a permit for the facilities, including the marine terminal, to be located within the coastal zone. During the local and regional proceedings, the County of Santa Barbara and Regional Coastal Zone Commission imposed a total of 76 conditions on their approvals, all of which were accepted by Exxon.

4. The Pipeline Issue

Opponents of the project appealed the Regional Commission's permit decision to the State Coastal Zone Commission. The State Commission's staff had adopted a position opposing the location of marine terminals within the Coastal Zone. They wanted instead to pipeline Santa Ynez crude oil as part of a strategy to eventually eliminate marine terminals. Exxon did not consider a pipeline to be a feasible alternative for Santa Ynez, due to numerous problems and uncertainties.

Because there is no pipeline in the vicinity of Santa Ynez, it would have been necessary to construct a new line. Although several alternative routes were considered, discussion with the

State Commission staff focused on a 140-mile pipeline to the Los Angeles harbor refining area. Refineries in the Los Angeles area have more than one million barrels per day of distillation capacity, but desulfurization capacity is limited. Accordingly, in Exxon's most optimistic estimation, the local refineries would take only 35 to 40 MB/D of the high-sulfur Santa Ynez crude oil. Thus, at the projected peak production rate of 80 MB/D, 50 to 60 percent of the crude oil would have to be loaded onto tankers in the Los Angeles area for transshipment to other refining centers.

Furthermore, Exxon was far from certain that the predicted production of 80 MB/D would ever be realized. Such a level of production would require additional platforms or similar structures at Hondo and the other two fields. With only the initial development at Hondo, production was expected to peak at about 27 MB/D. Exxon did not believe a pipeline costing $60-70 million could be justified for that level of production.

In spite of the problems and uncertainties of a pipeline, Exxon spent several months negotiating with the State Commission and its staff to find a suitable compromise. The company offered to spend $500,000 for preliminary engineering studies and preparation of an environmental impact report for a pipeline. If the studies indicated that a pipeline would be economically and environmentally sound, Exxon was willing to begin the process of obtaining necessary permits from the more than 14 government entities having jurisdiction along the 140-mile route to Los Angeles. Additionally, Exxon offered to spend up to $40 million for its share of a common-carrier pipeline that would be available to all producers in the area if the company developed production in excess of 40 MB/D, necessary permits could be obtained, and other producers committed reserves and financial participation to the pipeline.

On March 3, 1976, after almost two years of effort to obtain required state and local permits, the State Coastal Zone Commission denied the Regional Commission's permit, rejected Exxon's offers, and issued a permit with conditions the company could not accept. In essence, the State Coastal Zone Commission's conditions required that Exxon build a pipeline to transport the oil to an unknown destination without a limitation on cost. The Commission's plan had severe economic disadvantages and no environmental advantages. Exxon brought suit against the Commission to prevent it from interfering with the Plan of Operations approved by federal, state, and local agencies. The Commission argued that it was not interfering with the development of the Santa Ynez Unit, since Exxon was free to use the approved offshore treating alternative. Exxon had hoped for quick resolution in the courts, which did not occur, and the suits were subsequently dropped.

Meanwhile, the Department of the Interior (DOI) re-evaluated the pipeline and tanker alternative, concluded that the State Commission's conditions were unreasonable, and met with the Commission's chairman and staff in an attempt to work out a solution.

These efforts were also unsuccessful. In July 1976, DOI reaffirmed its prior approval of the offshore treating alternative. Exxon therefore proceeded with the OS&T facility and had spent more than $80 million on it. Adding to that the cost of the platform, leases, and exploratory work, Exxon had more than $500 million invested in the Santa Barbara Channel before it had produced the first barrel of oil.

Exxon believed that DOI's reaffirmation of the OS&T facility in July 1976 would end the uncertainty surrounding approval of the offshore plan. However, in November 1976, the State Commission filed suit seeking an injunction to stop use of the OS&T facility. The court denied the state's request. Then, in January 1977, the State of California and Santa Barbara County requested the new Secretary of the Interior to revoke DOI's approval of the OS&T facility. A great deal of correspondence followed, including proposed new onshore permit conditions from the State of California. However, near the end of August 1977, some eight months later, DOI advised the state that it would not revoke Exxon's offshore approval. Thus, the OS&T facility was affirmed for the third time.

The OS&T facility is basically an oil-treating facility similar to many that Exxon operates. One exception, though, is that the facilities were installed on the deck of a converted tanker. The OS&T facility is moored near the platform in federal waters. Oil produced at the platform is pipelined to the OS&T facility, where it is treated and stored in the vessel's cargo tanks. The treated crude oil periodically is loaded onto a shuttle tanker for delivery to refineries. A portion of the gas produced at the platform is treated on the OS&T facility to remove hydrogen sulfide and is then burned as fuel in gas turbines used to generate electricity for the operation.

6. Water Discharges

In September 1976, EPA advised Exxon that an NPDES permit would be required for discharges from the OS&T facility. Because this OS&T facility is a vessel, the company believed that such a permit would not be required. Discharges from the OS&T facility are mainly seawater (cooling system, segregated ships ballast, fire water system) and treated sanitary and domestic waste. All of the discharges meet or are better than federal and state specifications. Exxon filed for an NPDES permit under protest. Neither EPA nor anyone else has found fault with the water discharges. The permit was finally issued in February 1978. Issuance was delayed for months while EPA attempted to place air emission conditions on the water discharge permit.

7. Air Emissions

The federal EIS considered potential air pollution effects, if any, due to operations of the OS&T facility. It concluded that there would be no significant effects. EPA participated in the preparation of the EIS, as did officials of the State of California

and Santa Barbara County. At no time during those proceedings did EPA or any other agency question the EIS's conclusion. Exxon retained consultants with expertise in the area and the results of their studies supported that position also, i.e., that project emissions would not significantly affect local air quality.

Exxon planned for many features that minimize those emissions. For example, the OS&T facility was designed so that hydrocarbon emissions from the production and storage of oil are virtually eliminated. All crude oil and water storage tanks are gas blanketed. As these tanks fill with liquid, the vapors expelled are collected, compressed, and routed into the fuel gas system on the OS&T facility, where they are consumed in the gas turbines.

In September 1977, EPA advised Exxon that an air permit would be required for the Santa Ynez facility. This was the first time that EPA claimed jurisdiction over air emissions from resource development on the OCS. Since the Clean Air Act Amendments of 1970 were enacted, more than 700 platforms and structures for oil and gas drilling, treating, and processing had been constructed on the OCS. Not one had been required to have a permit.

8. Summation

This case history highlights the difficulties of one oil producer in its attempts to develop offshore reserves. Three EISs were prepared. Twenty-one major public hearings (and numerous working sessions with various staff groups) were held. The development received 10 major government approvals, and the onshore plan was approved by the voters in a county-wide referendum. In addition, the offshore treating plan was reviewed and affirmed several times. Twelve lawsuits were filed in connection with exploration and development of the Santa Ynez Unit leases, some initiated by Exxon. Exxon invested over $380 million in the Santa Ynez Unit and more than $500 million in the Santa Barbara Channel. After 13 years of planning, hearings, and litigation, Exxon began producing oil from the Hondo project in April 1981.

II. Refining

A. Construction Trends

Recent investments in refining capacity have been applied more to the expansion and modernization of existing plants than to the development of grassroots facilities. From 1970 to 1979, domestic refining capacity increased by 44.3 percent. Of this growth, 88 percent was by expansion of existing facilities and 12 percent by new plants.[16] There were 71 grassroots projects built during this period, but due to the "small refiner bias," most were quite small. Forty-four had capacities of less than 10 MB/D. Only four major refineries of capacity greater than 100 MB/D were constructed (Table 83).

It is important to note that the siting and permitting requirements of these major projects were completed in the early 1970's.

TABLE 83

Refineries of Greater than 100 MB/D Capacity
Constructed from 1970 to 1979

Firm	Location	Year	Capacity (1/1/79) (MB/D)
Atlantic Richfield	Ferndale, WA	1971	106
Gulf Oil	Belle Chasse, LA	1971	196
Mobil Oil	Joliet, IL	1972	180
Marathon	Garyville, LA	1975	200

Subsequent development of permitting requirements and procedures pose significantly greater risks for delay than these above-mentioned projects experienced, and it is conceivable that these projects would not be approved under today's permitting requirements.

Opposition to new large refineries on the East Coast has prevented any new siting there within the past 20 years. Firms that propose a large grassroots project on the East Coast typically expect a delay of five to 10 years to obtain all permits. A substantial risk of ultimate denial is also recognized. Table 84 lists 20 projects, mostly of large size refineries, that were planned but never built.

B. Project Lead Time and Planning

The construction of a large grassroots refinery is now expected to take about five years from the the time front-end engineering begins. During the preliminary engineering phase, it is assumed that an environmental assessment will be prepared and permits applied for. If the selected site does not pose any critical environmental or social problems and the project receives support from the state government and local community, all permits could be expected in two to four years. During this period, management decisions will be made about how far to go with land purchase, site preparations, and design engineering. Each of these steps will involve multimillion-dollar investments. Outlay of this much capital will be based on management's judgment of the risk of obtaining permit approvals without undue delay. After about one year of engineering, purchase contracts will be executed for prefabrication of major refinery components, such as pressure vessels, major pumps, gas compressors, and piping. Purchase contracts of this type provide for a cancellation fee, because these items are uniquely designed for a large refinery. It is preferable for major permits to be obtained prior to issuing purchase contracts in order to minimize risk of cancellation costs.

TABLE 84

Refineries Planned on the East Coast, But Not Constructed Due to State or Local Opposition (Prior to 1978)

Company	Location	Planned Capacity (MB/D)	Final Action Blocking Project
Ashland Oil	Ft. Pierce, FL	250	Corporate decision
Belcher Oil	Manatee County, FL	200	Voted against in referendum September 10, 1974
C.H. Sprague & Son	Newington, NH	50	Voted down in community vote on June 28, 1974
Commerce Oil	Jamestown Island, RI Narragansett Bay	50	Opposed by local organizations and contested in court
Crown Central Petroleum	Baltimore, MD	200	Local zoning
Fuels Desulfurization	Riverhead, NY	200	State reacted by legislature passing bill forbidding refineries in coastal area
Georgia Refining	Brunswick, GA	200	Blocked through actions of Office of State Environmental Director
Gibbs Oil	Sanford, ME	250	State action
Granite State	Rochester, NH	400	Corporate decision
In-O-Ven	New London, CT	400	Abandoned due to opposition from state government and citizen groups
JOC Oil	Jersey City, NJ	50	State action
Maine Clean Fuels	Searsport, ME	200	Maine environmental protection board rejected proposal
Maine Clean Fuels	South Portland, ME	200	City council rejected proposal

TABLE 84 (Continued)

Company	Location	Planned Capacity (MB/D)	Final Action Blocking Project
Northeast Petroleum	Tiverton, RI	65	City council rejected proposal
Olympic Oil Refineries	Durham, NH	400	Withdrawn after rejection by local referendum
Pepco	Saybrook, CT	400	Local zoning and state action
Saber-Tex	Dracut, ME	100	Corporate decision
Shell Oil	Delaware Bay, DE	150	State reacted by passing legislation forbidding refineries in coastal area
Steuart Petroleum	Piney Point, MD	100	Rejected by county voters by referendum on July 23, 1974
Supermarine	Hoboken, NJ	100	Withdrawn under pressure from environmental groups

SOURCE: Department of Energy, Trends in Refinery Capacity and Utilization, September 1978; Energy and Environmental Analysis, Inc., "Briefing for the American Petroleum Institute," November 16, 1978.

However, some components require more than a year to prefabricate, so there will be a critical point in the schedule to release purchase orders to meet a planned completion deadline. During the early engineering phase, an elaborate schedule is prepared to manage the project development. The schedule identifies all critical times for achieving completion of steps, including issuance of permits. Construction of facilities beyond site preparation is not allowed until the EIS is approved and major permits are issued. An unplanned delay can penalize the return on investment severely. This risk is usually avoided if the company has any chance of expanding and modernizing existing facilities rather than developing a new site.

A plant modification project can usually be permitted in one to two years, assuming the plant has already been operating under major permits. Usually there are some obsolete operations that can be retired and often the entire project can be designed to provide an environmental improvement. The "bubble concept" is a method of analyzing a project proposal as if the entire plant were covered with a glass bubble. Emission reductions from curtailing old operations can be used to offset emissions from new equipment. In many cases projects have been approved without the need for an EIS. The risk of a permit delay is significantly less for a modification project than for a grassroots facility.

Factors to be considered in the siting analysis include:

- Pipeline transportation availability (crude oil and products)
- Land transportation access (highway and railroad)
- Water transportation (dock facility and depth of draft)
- Utility availability and costs (power and water)
- Fuel supply (coal, oil, gas)
- Land availability and cost
- Labor availability and cost (construction and operating)
- State and local taxes
- Permit requirements and approval time.

Of these factors to be considered, the one that is most difficult to determine or estimate accurately is permitting. The risk of delay is known to be significant and has kept many proposals from ever being developed beyond a preliminary screening of alternatives. Companies have avoided the risk of uncertainty and delay by electing to modify and expand existing facilities, rather than try to develop a new site. This trend is readily apparent by comparing the levels of investment made for plant modifications and expansions to the lack of investment in large grassroots facilities since 1975.

C. Generalized Permit Critical Path Flowchart

Figure 104 is a critical path flowchart for obtaining the major permits for a new refinery in an area classified as attainment for air quality standards. The PSD permit is a requirement of the Clean Air Act. The NPDES and Section 404 (dredge and fill) permits are requirements of the Clean Water Act. An environmental impact assessment is always required, and a project of this magnitude will almost always require a federal lead agency to issue an EIS. A minimum of 24 months is expected for this procedure in the most optimistic circumstances.

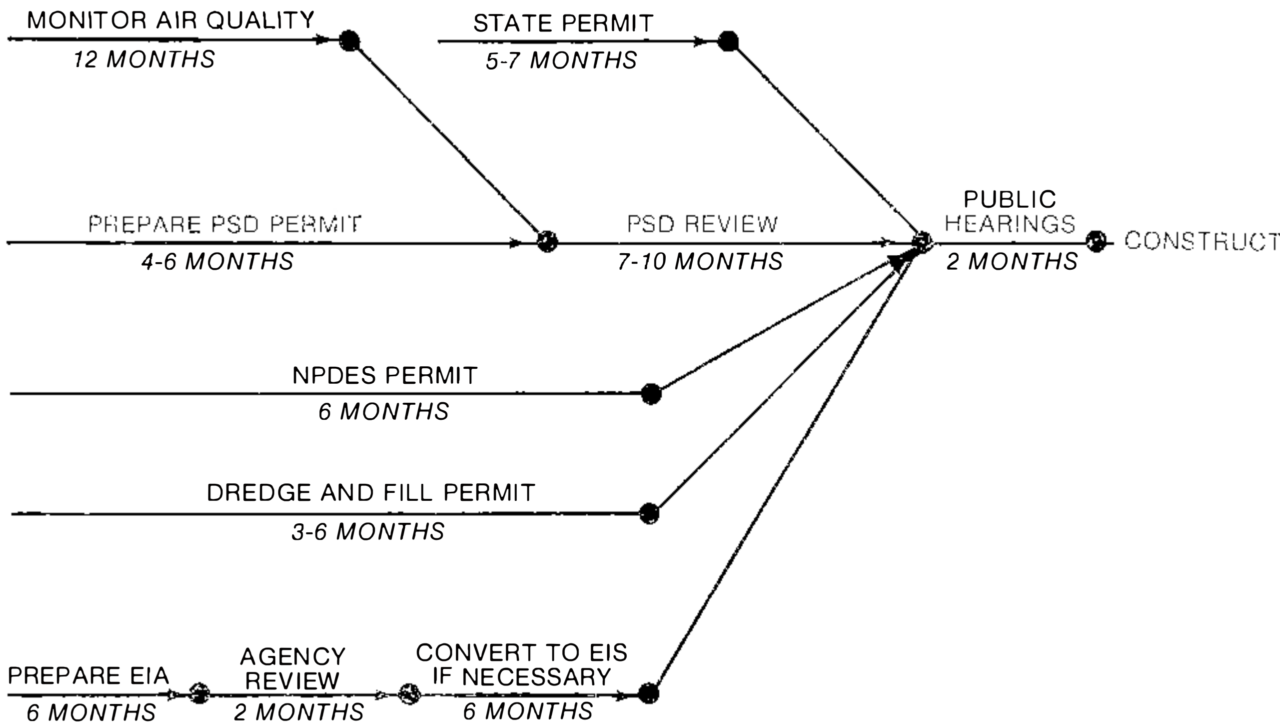

Figure 104. Typical Refinery Complex Permit Timing.

D. Environmental Assessment

The siting of a new refinery requires an environmental assessment, which will include an analysis of the impacts on air quality, water quality, land use, transportation systems, and other aspects of society.

1. Air Quality Impact

Although no large refineries have been built in the United States since 1975, a few proposals have been advanced through the permitting process. As an example of such a project in an attainment area, EPA issued a PSD permit in April 1981 to the Virgin Islands Refining Company for construction of a 200 MB/D refinery at St. Croix, V.I. The permit was issued after the applicant demonstrated that the emissions from the new refinery would not cause air quality standards to be exceeded. The applicant was able to demonstrate this satisfactorily by using modeling techniques approved by EPA, after acquiring 12 months of meteorological data. The modeling predicts where the worst concentration of pollutants will occur.

The permitting of a new facility in a nonattainment area requires offsets of emission reductions from other sources in the same area. An example of such a proposal is the Hampton Roads project in Portsmouth, Virginia. The area is classified as nonattainment for hydrocarbons. A construction permit was issued

after an acceptable offset arrangement was provided. The State of Virginia, highly supportive of the refinery proposal, provided the hydrocarbon offsets by changing the materials used for paving roads. The asphaltic material previously used caused the evaporation of hydrocarbons in large quantities. The state agreed to use different paving materials and applied the emission reduction as an offset against the Hampton Roads proposal.

2. Water Quality Impact

Section 402 of the Clean Water Act established a permit program under the NPDES. This permit program has been effective in controlling the quality of wastewater discharges from petroleum refineries. The goals of the Clean Water Act have not been met, and cannot be met until municipalities and non-point sources of pollution are brought under the high standards of control already achieved by many industries, including petroleum refining.

3. Land-Use Impact

A modern large refinery requires a minimum land area of 800 acres. Additional area may be required for special conditions of petroleum storage or distribution, or if environmental factors require a buffer zone to be established. Other land-use factors that may require assessment cover a temporary period of construction followed by the more permanent period of operations. The number of people employed during construction may peak in the range of 2,000 to 4,000, compared to the permanent operating work force of 500 to 800. The construction period will last two or three years. If the site is within 50 miles of a large population center, the impacts on housing, traffic patterns, utilities, school enrollments, and community activities will not be significant. If the site is more remotely located, temporary housing may be required for construction workers. The social and cultural impacts of a refinery in a rural area will be similar to those for a synthetic fuels project.

III. Synthetic Fuel Plants

A. Siting

The large quantities of coal and oil shale required to sustain operation of projected synfuel facilities would indicate that siting of such facilities may be dictated to a large degree by the location of coal and oil shale deposits. This minimizes the costs of transporting vast quantities of raw material to a processing facility. However, other economic, engineering, or environmental considerations might make remote siting of the processing facilities (plant site distant from mine site) an attractive and feasible alternative.

In the western United States, coal deposits in Colorado, Montana, North Dakota, and Wyoming offer good prospects for synfuel plant sites. Oil shale deposits in Utah and Colorado provide promise for siting oil shale processing plants. In the eastern

section of the United States, the states of Illinois, Kentucky, and West Virginia, for example, contain adequate coal deposits to sustain operation of coal conversion plants. Oil shale deposits in Illinois, Indiana, Ohio, Kentucky, Tennessee, and West Virginia makes these states attractive as potential sites for oil shale conversion plants.

Important siting factors will include the availability of adequate water supplies and the ambient air quality. Synfuel facilities will compete with existing water users and with new users for available water supplies. Synfuel facility use includes water for cooling, steam generation, waste disposal, environmental control, and production of hydrogen. Similarly, synfuel facilities will also compete with other facilities for use of available sulfur dioxide and total suspended particulate increments. A particular problem may exist in areas where coal-fired electric power plants are sited.

B. Project Lead Time and Planning

A DOE report indicated that, based upon an analysis of federal and state permit requirements for major power plants, a permitting period of two to three years would be expected.[17] The National Petroleum Council believes that a two to four year period is more realistic. This permitting period follows the completion of pre-permit environmental data collection and monitoring.

Pre-permit environmental data collection and monitoring might require, as a minimum, a period of one to two years. Therefore, a total time of three to six years may be required from the start of environmental data collection and monitoring to the receipt of the last permit or environmental approval.

The issuance of a PSD permit under the Clean Air Act would require a minimum of one calendar year for a major synfuel facility. For first generation plants, PSD may not pose a large problem. However, as PSD increments are used there may not be adequate increments remaining to allow approval of later plants. NPDES permits could be issued in about one year.

These permitting time estimates do not reflect any consideration of delays encountered by third party litigation.

1. Air and Water Permits

Synfuel processes are developing technologies, comprising existing as well as new industry operations. Some questions resulting from the new aspects remain unanswered with respect to air, water, and solid waste emissions. Lack of actual operating data from commercialized facilities hampers the development of realistic pollution control guidelines for most synfuel technologies. This lack of guidelines has forced the regulatory agencies to issue permits for pilot and pre-commercial scale operations on a case-by-case basis. Negotiation of these site-specific requirements has been and could continue to be a source of conflict resulting in delay in the permitting process.

The use of BACT to control air emissions is required for PSD permits. For those facilities wishing to locate in a nonattainment area, use of LAER technology is required. What LAER is, how it is to be determined, and upon what it is to be based are only a few of the questions that must be answered. Disagreement on these issues seems inevitable. Resolving these disagreements will be time consuming. The Clean Air Act's visibility requirements, many of which are still undefined, may become the limiting factor in siting facilities in the general proximity of Class I areas.

Similarly, for the wastewater discharge questions, effluent guidelines and standards have yet to be developed. Companies applying for wastewater discharge permits are faced with negotiating acceptable permit limitations with the agencies on a case-by-case basis. The opportunity for delay can also occur when the proposed wastewater discharge permit is issued for public review. Public hearings are likely to be held, providing the opportunity for third party intervention.

2. Other Permits

The permit issuance process for most other permits has similar public review periods. With controversial projects, it is anticipated that these reviews will be rather lengthy. Decisions on the part of the regulators in the face of such public interest will not be made quickly.

C. Environmental Assessment

The 1980 DOE study, Synthetic Fuels and the Environment, analyzed the regulatory and environmental impacts that may affect a synfuels development program. Appendix D of this report comments on that study. Among the topics considered in the report were environmental impact analyses for potential oil shale and coal resource locales. These analyses were performed on a regional basis. Issues addressed included air quality, water availability, water quality, community development, fish and wildlife, vegetation disruption, and federal lands multiple-use planning. Other issues addressed include long-range air quality impacts, global carbon dioxide concentrations, waste disposal requirements, and product/process safety impacts.

It is impossible in a report of this nature to fully assess the ecological impact of synfuel development in the United States. Specific impacts would be evaluated on a site-specific basis, presumably in the EIS.

The single greatest source of impact on the ecology will be that associated with the surface mining activities. The removal of surface vegetation, the stripping of topsoil, and possibly the relocation of streams to allow mining, destroy wildlife habitats and could possibly destroy historical and archaeological artifacts on the site unless special care is taken to preserve them. Loss of

wilderness area, prime farmlands, grazing lands, and habitat for endangered species are other expressed concerns.

The DOE report evaluated the four resource areas in terms of ecological sensitivity. Factors assessed were ecosystem quality, disturbance susceptibility, and rehabilitation potential. The following sections summarize the findings contained in the report.

1. Northern Plains Resource Area

Most of the Northern Plains Resource Area ranked high in land disturbance potential because little of the area at present has been disturbed. Generally, agricultural ecological system impacts were low, except in certain counties in North Dakota and Montana. Natural ecological system impacts were rated high because of woody draws for wildlife habitat, habitat for endangered species, and certain streams. Rehabilitation potential varied throughout the resource area.

2. Four Corners/Rocky Mountain Resource Area

The Four Corners/Rocky Mountain Resource Area is characterized as having a high ecological sensitivity ranking. Similarly, most areas were ranked high for disturbance potential based on population. Most regions of this resource area were ranked as having a fairly high impact on rehabilitation potential with the exception of western Colorado, which was considered to have average potential.

3. Mideast Resource Area

In the Mideast Resource Area, natural ecological sensitivity was ranked low; the rankings were dominated by agricultural cropland considerations. The land disturbance factor was rated high because of the high population density. Rehabilitation potential was ranked high because of the requirement to return the mined sites to prime farmland.

4. Appalachian Resource Area

The Appalachian Resource Area is ranked as having the lowest ecological sensitivity of all the areas studied. Natural ecological systems were ranked fairly high because of the presence of endangered species, mountainous terrain, and significant waterways. High levels of historical land damage resulted in a low ranking for land disturbance potential.

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CHAPTER EIGHT

OTHER ISSUES OF THE 1980'S

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Environmental issues that the National Petroleum Council (NPC) believes may be significant in the 1980's are briefly mentioned in the Executive Summary. There are several other issues whose causes are not clearly defined and that are affected by many factors and industries, of which the petroleum industry is only one. Of concern are: the ecological and public health effects of, and the control strategies for, acid rain; CO_2 "greenhouse" effect; groundwater contamination; and indoor air pollution. Groundwater contamination is discussed briefly in Chapter Four. The remaining issues and the setting of National Ambient Air Quality Standards (NAAQS) are discussed below.

ACID RAIN

The phenomenon of "acid rain" has lately drawn increasing attention because of claims that it is causing environmental damage in the United States and Canada. These claims have been criticized by some as unproven. While there are indications that there have always been occurrences of natural acid rain, there are also indications that man-made pollutants from the combustion of fossil fuels contribute to the acidity of rainfall. These basic disagreements highlight the uncertainties that policymakers confront as they decide what course of action should be followed to deal with the acid rain issue.[1] Congress recognized these uncertainties when it enacted Title VII of the 1980 Energy Security Act, which authorizes $50 million to be spent over the next 10 years to obtain information on the causes, extent, and effects of acid rain.[2]

I. Definition of Acid Rain

Acid rain is the common term for the more general phenomenon of acid deposition. Acid deposition includes acidic snow, sleet, fog, and particulate matter as well as acid rain. Pure water saturated with carbon dioxide (CO_2) yields a pH of 5.6, but both natural processes and man's activities can change it. Acid rain commonly refers to even lower pH values. The acid content of rain is generally about 60 percent sulfuric acid, 30 percent nitric acid, and 10 percent hydrochloric acid. There may be small concentrations of organic acids present. These proportions vary with region and time.

II. Influences on the Acidity of Rain

The acidity of rainfall is influenced by the amount and kind of gases dissolved in it. These include sulfur dioxide (SO_2), nitrogen oxides (NO_x), hydrogen chloride, and ammonia. Particulate matter may also influence rainfall acidity as well as heavy

metals, which can catalyze the formation of stronger acids in rain. All have natural and man-made origins.

There is increasing evidence that SO_2 and NO_x emissions that come primarily from the burning of fossil fuels cause acid rain. One report has suggested that local oil-fired sources (utility, residential, and commercial boilers) may contribute to precipitation acidity because burning oil produces sulfates directly in the boiler, and produces catalytic materials that catalyze the transformation of SO_2 into sulfates in the atmosphere.[3] Oil-fired sources also generate NO_x. To determine whether these beliefs are valid, it is necessary to know the relationship between SO_2 and NO_x emissions and the pH of rain. However, this emissions/pH relationship is very complex and consists of at least six components:

- Amount of SO_2 and NO_x emissions
- Mechanism (especially conversion rates) by which SO_2 and NO_x emissions are converted into sulfates and nitrates
- Atmospheric transport of pollutants, including meteorological factors
- Efficiency with which clouds incorporate pollutants
- What happens within the clouds that affects the acidity of rain
- Changes in the raindrops as they fall through the atmosphere.[4]

Except for the amount of emissions, which is fairly well known for anthropogenic sources, knowledge about the remaining five components is limited.[5] This lack of knowledge prohibits prediction of what effect a given level of SO_2 and NO_x emissions (or emissions reduction) will have on the acidity of rain.

III. Effects of Acid Rain

There is no consensus among researchers about the types and magnitude of the potential adverse impacts of acid rain. However, acid rain can affect aquatic and terrestrial ecosystems, soils, materials, and structures, and even man (indirectly). Most of the data available on impacts of acidic precipitation are derived from studies of the effects of increased acidity on aquatic organisms.[6]

The acidification of Scandinavian lakes has been attributed to acid rain. Lakes with depleted fish populations and disturbed biota have been discovered in the northeastern United States and eastern Canada. It is widely assumed that the condition results from acid rain, but this conclusion has not been proven. For instance, local runoff from bogs, polluted streams, and mine drainage

can be acidic, and surrounding bedrock and soils have different capabilities to neutralize acid deposition.[7]

Some observed effects of acidified lakes include uptake of heavy metals by aquatic biota, loss of young fish and other aquatic animals, and elimination of algae and other aquatic plants.[8] However, the acidity of freshwater lakes reflects not only the acidity of precipitation, but also the acidity of local inputs (bogs, polluted streams, mine drainage, and runoff over watershed areas) and the capacity of the bedrock and soils of its watershed to neutralize acid deposition.[9]

The effects of acid rain on vegetation observed in controlled studies have been both detrimental and beneficial. On one hand, injury to leaves and the induction of lesions in crops and trees have been noted; while on the benefit side, stimulation and enhanced growth of crops and trees have been observed. In addition, both inhibition and increased incidence of diseases in certain crops have been noted.[10]

The potential impacts of acid rain on vegetation and soils have been studied in laboratory experiments using simulations of exposure to acid rain. Frequently, the simulated rain has been more acidic than natural rain. According to one report, there has been no visible or detectable damage to terrestrial ecosystems outside the laboratory.[11]

Laboratory studies have shown also that leaching of some soil nutrients is accelerated by increased acidity. Other scientists have shown that soil fertility may be increased by the deposition of nitrates and sulfates (typical components of fertilizer) in acid rain.

Acid deposition is known to corrode metals, building materials, paints, and other surface coatings. This is likely a complex phenomenon enhanced by other pollution processes.[12]

Few studies have been reported on the direct health risks from exposure to acid precipitation. There are claims that, potentially, the increased presence and ingestion of heavy metals in acidified drinking water could represent a health risk.[13] However, reported concentrations of heavy metals in waters analyzed have been orders of magnitude below public health drinking water standards.[14]

Thus, while laboratory studies have shown that potential problems may exist, these studies generally have not been confirmed by field observations. It is difficult to assess the effect of acid precipitation on many ecosystems against a background of differences caused by annual climatic variation. Additional research to determine the true state of effects is needed.

The need for further research was also noted by the Committee on the Atmosphere and Biosphere of the National Research Council (NRC).[15] The NRC published the results of its literature review

in October 1981, pointing out that scientific evidence on acid deposition is "incomplete in many respects." However, it "renders a rather unfavorable picture of the consequences of current fossil fuel burning practices." It says that "the picture is disturbing enough to merit prompt tightening of restrictions on atmospheric emissions from fossil fuels...." It further concludes that "atmospheric pollution and its consequences deserve major consideration when the sources and sites of energy production are decided. However, much remains to be done if we are to adequately reassess the ecological significance of atmospheric pollutants generated by different energy systems." The text of the report is a thorough analysis of the effects of acidity on aquatic and terrestrial ecosystems; however, the study is not definitive because critical questions such as atmospheric transport and transformation are not explained in detail.

IV. Trends in Rainfall Acidity

There appears to be no clear evidence that rainfall acidity is increasing. Most of the claims of increasing rainfall acidity are based on maps published by Cogbill and Likens.[16] These maps show pH contours, which are based on calculated pH values. The reported trend toward increasing acidity is controversial, however, because rainfall data were acquired at different sampling stations, operated over different time periods, and with different sampling methods. Reanalysis of the Cogbill-Likens data by examining trends at the same stations have shown there is no discernible trend in rainfall acidity.[17]

Other studies reach similar conclusions. For example, continuous measurements taken over a 10-year period at a station in Hubbard Brook, New Hampshire, revealed no statistically significant trend in rainfall acidity.[18] The U.S. Geological Survey's 13-year monitoring program in New York State also failed to show a significant trend in rainfall acidity.[19]

V. Acid Rain Controls

It may well be that source correction is the most costly, and possibly the least effective, mitigation strategy. The imposition of more stringent emission limitations on large stationary sources that emit SO_2 and NO_x has been advocated. Although numerous sources emit these pollutants, the proponents of controls have, thus far, focused their concerns on SO_2 emissions from coal-fired power plants.

The present Clean Air Act contains no statutory provisions expressly dealing with acid rain. The Environmental Protection Agency (EPA) recently conducted an analysis of the Act and concluded that any further emission controls on large sources of SO_2 and NO_x were either impractical or legally un up ortable Hence, the current reauthorization of the Clean Air Act is likely to serve as a forum for discussion of acid rain.

In spite of a lack of explicit authority for EPA to address acid rain, the Clean Air Act and EPA and state regulations presently impose significant and costly emission limitations on coal- and oil-fired boilers, especially power plants. Specifically, these emission limitations include New Source Performance Standards (NSPS), Best Available Control Technology, Lowest Achievable Emission Rate, Reasonably Available Control Technology, and Best Available Retrofit Technology. Other Clean Air Act requirements that serve to limit SO_2 and NO_x emissions include NAAQS, Prevention of Significant Deterioration (PSD) increments (for attainment areas), stack height credit (limiting the use of tall stacks), and "reasonable further progress" requirement (net decline in emissions in nonattainment areas).

Nationally, SO_2 emissions are predicted to decline from 19.4 million tons in 1979 to 18.9 million tons in 1990, and to 18.5 million tons in 2010.[20] Because certain key assumptions underlying these predictions are very conservative (e.g., natural gas will no longer be available by the year 2000), SO_2 emissions may decline even more.

National NO_x emissions in 1977 were attributed to transportation (43 percent of total NO_x emissions), utility fuel combustion (35 percent), industrial fuel combustion (12 percent), and other sources (10 percent).[21] Current Department of Energy projections indicate that NO_x emissions from utilities and industrial sources may rise between 1980 and the year 2000.[22]

VI. Impacts of Control Strategies

The potential acid rain control strategies that EPA examined recently focused on various ways to reduce SO_2 emissions at existing coal-fired power plants, because new plants are already subject to very stringent NSPS for SO_2 and NO_x. Basically, the cost of these control strategies (if EPA were given authority to implement them) could discourage the use of existing coal-fired capacity because of the expense associated with additional SO_2 control. If preliminary assertions concerning the contributions of oil-fired boilers to sulfate levels (and presumably to acid rain) are borne out, additional controls might also be imposed on existing oil-fired boilers, affecting the cost of oil-generated electricity and therefore the demand for oil. In any event, because of the expense of additional controls, the ultimate effect of acid rain-based controls could be to make electricity more expensive and therefore less competitive with substitute energy sources, such as natural gas. This could reduce the demand for both coal- and oil-fired boiler capacity and increase the demand for substitute energy sources, such as nuclear energy and natural gas.

To the extent that NO_x emissions emerge as a key factor in the acid rain controversy, additional emission reductions could be required for mobile sources. Given the state of the U.S. automotive industry, any such move would be very controversial. The added expense of new motor vehicles could inhibit sales of newer, more efficient models, and thus contribute to a slowing in the anticipated decline in the demand for gasoline.

Finally, the imposition of additional regulations based on acid rain concerns could contribute to the uncertainties facing those industries that operate sources that emit acidic precursors. As the causes and effects of acid rain are not yet well understood, no final control strategies should be established. In light of the large number of uncertainties surrounding acid rain in both the scientific and policy areas, there is a need for accelerating completion of the 10-year study required by Title VII of the Energy Security Act of 1980.

CO_2 "GREENHOUSE" EFFECT

The CO_2 "greenhouse" effect is a postulated global climate change resulting from higher atmospheric CO_2 concentration not yet detected in global temperature measurements. Like acid rain, the problem is universal and not limited to the oil and gas industries. It is based upon the fact that CO_2 in the atmosphere is transparent to ultraviolet rays in sunlight but is opaque to some of the infrared (heat) radiation to which a portion of the sun's ultraviolet light is converted when it strikes the earth. This means that if the CO_2 content of the atmosphere increases, it would tend to prevent the reradiation to space of some of the sun's energy and one of the results could be a change in climate, including an increase in the average global temperature. Callendar conjectured that the rapid increase in the burning of fossil fuels which has occurred since the start of the Industrial Revolution will result in an increase in the CO_2 concentration in the atmosphere.[23] C. D. Keeling, at Mauna Loa Observatory, Hawaii, initiated in 1958 a program of CO_2 concentration measurement in the atmosphere, which has been essentially continuous ever since.[24] Data from Mauna Loa and three other locations are shown graphically in Figure 105. Seasonal variations, such as rates of photosynthesis and seasonal ocean temperature changes, are apparent and of interest. The relatively close agreement in absolute quantities and the similarity of the trends at each of the sample locations have established a global increase in atmospheric CO_2 as a credible phenomenon.

The coincidence of this increase with the increase in combustion of fossil fuels since about 1860 has led to a widely accepted conclusion that the burning of fossil fuels is a significant, if not the major, contributor to a real increase in atmospheric CO_2. By 1974, the burning of coal accounted for 28 percent of CO_2 production, oil for 35 percent, and natural gas for 19 percent.[25] It is also recognized that agricultural practices such as "slashing and burning" can add to atmospheric CO_2 by both the burning of forest biomass and the concomitant reduction in photosynthetic removal of CO_2.[26] Also, in 1974 the CO_2 released by man-made sources in major areas was: United States, 27 percent; Western Europe, 18 percent; Soviet Union, 16 percent; other, 39 percent.[27] Therefore, the CO_2 problem, if there is one, will require joint action by major powers, because unilateral action by an individual country or small group of countries will not suffice.

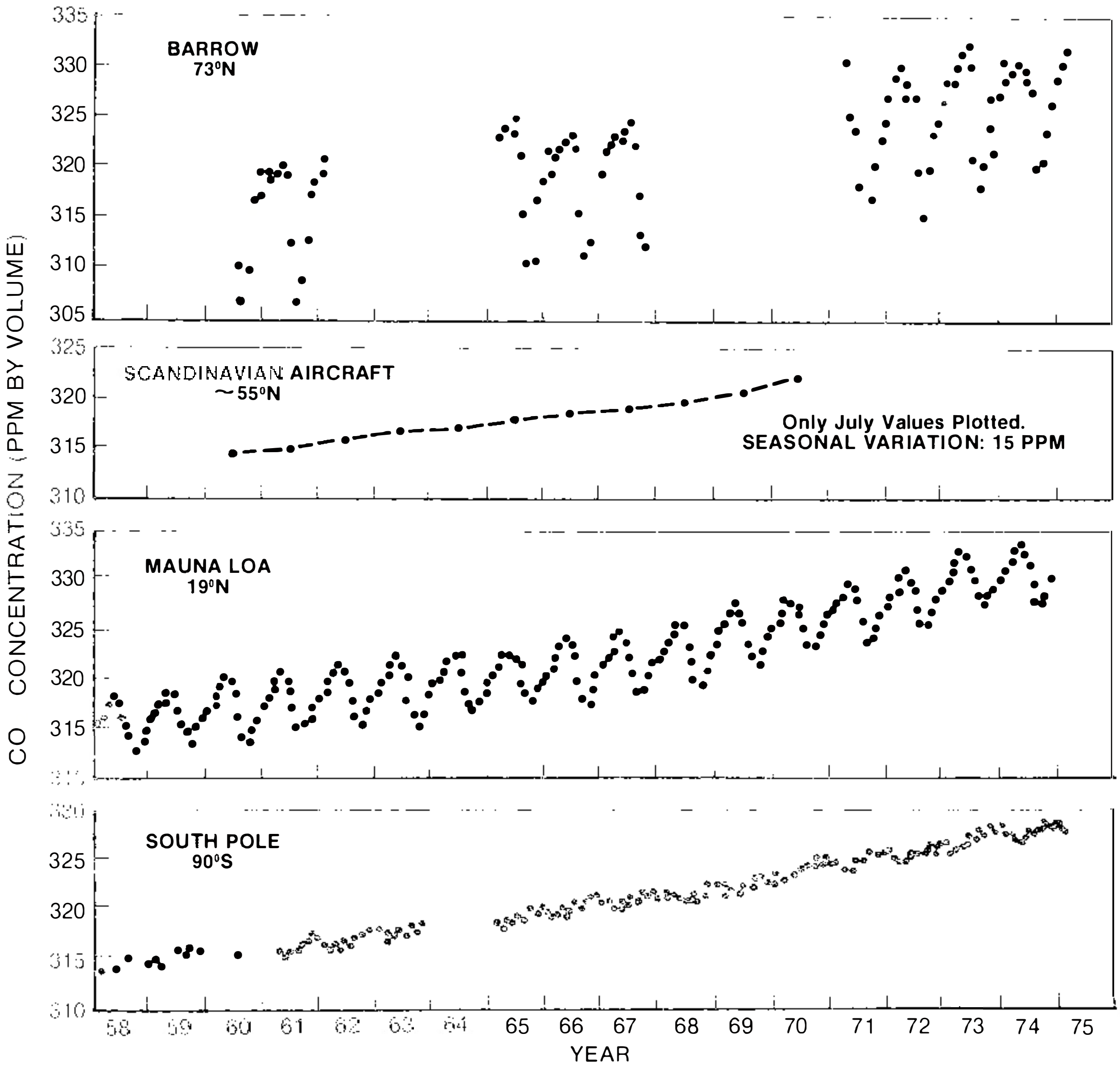

Figure 105. Measurements of CO_2 Concentration in the Atmosphere at Selected Stations.

SOURCE: Machta, L.; Hanson, K.; Keeling, C.D., "Atmospheric Carbon Dioxide and Some Interpretations," *The Fate of Fossil Fuel CO_2 in the Oceans*, Plenum Press, 1977.

The question as to whether there will be a CO_2 problem has generated considerable debate. The one fact that scientists in this field seem agreed upon is that there has been an increase in global atmospheric CO_2 content from about 315 parts per million volume (ppmv) in 1958 to about 335 ppmv or slightly more today. The cause of this increase is generally attributed to the large quantities of fossil fuel being burned.

The oceans are a very large potential sink for CO_2 and therefore represent a very large unknown. The chemistry of CO_2 absorption in water is well understood and quantified, although there

remain questions as to rates and equilibria in seawater. The rates of CO_2 (or carbonate ion) exchange between the atmosphere and surface waters and deeper waters, and the effects of the varying temperatures of ocean waters in different currents and different oceans all are poorly defined as are all of the currents and "turnover" rates, which are of maximum importance in determining the rate of the mixing of additional CO_2 into the oceans.

There have been many good estimates of the total carbon in the biosphere and the rates of exchange due to such processes as photosynthesis and decomposition. There have been several competent attempts to make mathematical models of the system and of its major parts.[28] All of these have added information, but the "area of ignorance" in the total subject remains very large. Madden and Ramanathau have stated that the temperature increase expected to accompany the observed CO_2 concentration increase since the start of the Industrial Revolution should be detectable now, particularly at higher latitudes. The instrumental record does not indicate such a temperature shift.[29] On the other hand, a recent paper by Hansen et al. indicates that indeed the global temperature has risen.[30]

The reason that the subject continues to cause debate and to stimulate research is that it is so very closely tied to the world energy problem. If fossil fuel combustion is the major cause of increasing atmospheric CO_2, if the increasing CO_2 content will result in large or possibly catastrophic climate changes, and if natural constraints are either inadequate or too slow to keep the situation stable, then action must be initiated fairly soon to reduce the discharge of CO_2 into the atmosphere.

This action could take the form of restrictions on the use of fossil fuels. The burning of all of the "recoverable resources" of oil (2 trillion barrels) and of gas (9,000 trillion cubic feet) only (not coal) could not raise the global CO_2 level (assuming an airborne fraction of 0.53) to 500 ppmv, which is considered acceptable.[31] The fossil fuels having much greater abundance, particularly coal, are present in sufficient quantity to cause unacceptable CO_2 (and temperature) levels.

Thus the CO_2 "greenhouse" effect may or may not be a serious problem in the future. If it will be a serious problem, plans and implementation strategies should be developed in the near future. The United States and the World Meteorological Organization are commissioning many additional CO_2 monitoring stations to provide a spatially distributed sampling network. Present meteorological stations should provide the necessary notice of a warming trend as soon as it can be differentiated from "normal" temperature fluctuations. The ability to differentiate must be developed. In the meantime, recognizing the immensity of the energy supply industry and the time required to make fundamental changes in such supply areas as raw material source, and recognizing that any mandated restrictions on fossil fuel use would no doubt require such fundamental changes, the petroleum industry must stay closely aware of progress in this field.

INDOOR AIR POLLUTION

This issue is now receiving increased attention and may be a major issue in the 1980's. It is a general concern that is broader than the petroleum industry. The issue is concerned primarily with those indoor contaminants that are generated or liberated indoors. When they reach high concentrations they may cause nuisances, irritation of sensitive tissues, illness, and in some cases death from acute as well as chronic exposures.

Most people spend on the order of 80-90 percent of their time in a house, an office, a factory, a store, or a public place such as a theater or a restaurant. There is an increasing amount of scientific data that show that indoor exposure to the criteria and other pollutants could be substantial, but there is little epidemiological evidence on the health effects of the indoor pollutants. Indoor exposure has been largely overlooked in research on the health effects of the environmental criteria pollutants even though it is now being recognized to be an important aspect of the total exposure to many pollutants.

Indoor air pollution in residences, public buildings, and offices is created for the most part by the people's activities and their use of appliances, power equipment, and household materials and chemicals; by wear and tear and deterioration of some of the structural and decorative materials; by thermal effects; and by the intrusion of outdoor ambient air pollutants. In some cases these criteria pollutants may represent the most important stress on human health and welfare and there is an increasing amount of scientific data available to establish their effects and establish standards.

Some of the pollutant sources (e.g., cigarette smoking) have been recognized for a long time, but their importance has only recently been evaluated. A number of sources are of concern only in the indoor environment; i.e., cooking and use of chemical consumer products, space heating devices, and certain floor and wall coverings. The expanded use of wood and coal for space heating along with kerosine and bottled gas, and use of products that liberate organic substances are a potential contribution to the contamination of indoor air space. In isolated cases, infectious microbes and allergenic agents can grow and contribute to the indoor problem.

A recent report by the Committee on Indoor Pollutants of the NRC has identified a number of specific pollutants and classes of pollutants as current or possible indoor pollutant problems.[32] These are:

- Radon
- Formaldehyde
- Asbestos

- Synthetic fibers
- Tobacco smoke
- Products of combustion
- Microorganisms and allergens
- Moisture.

Ventilation alone may not be sufficient to dilute indoor pollution to an acceptable level and may be inappropriate for a variety of reasons; i.e., not available, not controllable, substantial energy penalties, and introduction of outside pollutants. The introduction of energy conservation systems to reduce ventilation could aggravate problems in indoor air quality, create new problems (nuisances), and perhaps be generally detrimental to health and welfare unless pollution control measures are taken.

There is no question that there is a great complexity to the study of human exposures that have multiple sources. The barriers between inside and outside air are not absolute, and ambient air contributes to indoor air. Outdoor and indoor air may react chemically to produce a different indoor effect. The development of effective and efficient control strategies for mitigating these suspected indoor problems requires a greatly improved understanding of the exposure levels, the human responses to the exposure, and pollutant interactions.

NATIONAL AMBIENT AIR QUALITY STANDARDS

During the 1970's, when the NAAQS were first established and in some cases revised, a great deal was learned about air pollution causes and effects. Improvements are needed in the way the NAAQS are established.

The NAAQS should be reviewed and revised both to reflect sound, up-to-date scientific evidence and to provide a balance with other important national goals. In other words, the NAAQS must be based on sound medical and scientific evidence and must protect public health and welfare with an adequate margin of safety. These standards should also take into account the important national goals of producing sufficient energy and maintaining a sound economy.

Some changes in standard setting that EPA could consider are:

- "Primary standards" are set at levels that protect the public health, plus a margin of safety. When setting that margin of safety, EPA should consider other relevant factors, such as attainability and incremental costs and benefits.
- Define adverse health effects and establish an acceptable methodology for evaluating health risks. EPA's criteria

documents and policy analysis documents should evaluate the studies that are used as a basis for deciding a pollutant's health effects. Moreover, EPA should recognize the importance of studies whose findings are supported in other studies. A qualified scientific body, the Clean Air Scientific Advisory Committee of the Science Advisory Board, should evaluate the studies used in EPA's criteria documents as well as the end product; i.e., the NAAQS. Before establishing a new or revising an old standard, EPA should be required to reconcile its findings with those of the scientific body reviewing these findings.

- Make sure that proposed NAAQS and exceedances of the NAAQS allow for the uncertainty in such factors as unique meteorological conditions, air quality monitoring, and air quality computer modeling. Proposed NAAQS should allow more flexibility in determining exceedances (instances when the specified air quality limit is exceeded), and take into account natural occurrences and emergency pollution episodes.

- Analyze additional costs and benefits and take regional differences into account in setting the secondary standards, those standards that are intended to protect property, plants, aesthetics, and other public welfare values.

The issue of how to set and attain the NAAQS, both primary and secondary, will be a major issue of the 1980's. The debate is just now heating up and will probably continue for some time until the NAAQS are revised and in place. As more knowledge is obtained, it is conceivable that this issue will be raised periodically and debated far into the forseeable future.

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APPENDICES

THE SECRETARY OF ENERGY
WASHINGTON, D.C. 20585

April 9, 1980

Mr. C. H. Murphy, Jr.
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Murphy:

In 1971, at the request of the Secretary of the Interior, the National Petroleum Council published a study report entitled Environmental Conservation. This report dealt with the environmental effects of the petroleum industry and has been of great assistance to Government officials making policy decisions involving pollution control regulations.

During the past decade, extensive new statutory and regulatory frameworks have been established in regard to environmental requirements affecting oil and gas operations. Additionally, significant technological advances in the oil and gas industry have occurred since 1971. These advances not only increase economic efficiency but mitigate environmental hazards as well.

I request that the National Petroleum Council undertake to update the 1971 report on Environmental Conservation. In this update, special emphasis should be placed on determining the environmental problems that are most serious and the impact of current environmental control regulations on the availability and cost of petroleum products and natural gas.

For purposes of this study, I will designate R. Dobie Langenkamp, the Deputy Assistant Secretary for Resource Development and Operations, Resource Applications, to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

C. W. Duncan

Charles W. Duncan, Jr.

Background Information on the National Petroleum Council

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of the Interior and the Department of Energy include:

- *Environmental Conservation—The Oil and Gas Industries* (1971, 1972)
- *U.S. Energy Outlook* (1971, 1972)
- *Potential for Energy Conservation in the United States: 1974-1978* (1974)
- *Potential for Energy Conservation in the United States: 1979-1985* (1975)
- *Ocean Petroleum Resources* (1975)
- *Petroleum Storage for National Security* (1975)
- *Enhanced Oil Recovery* (1976)
- *Materials and Manpower Requirements* (1974, 1979)
- *Petroleum Storage & Transportation Capacities* (1974, 1979)
- *Refinery Flexibility* (1979, 1980)
- *Unconventional Gas Sources* (1980)
- *Emergency Preparedness for Interruption of Petroleum Imports into the United States* (1981)
- *U.S. Arctic Oil and Gas (1981)*

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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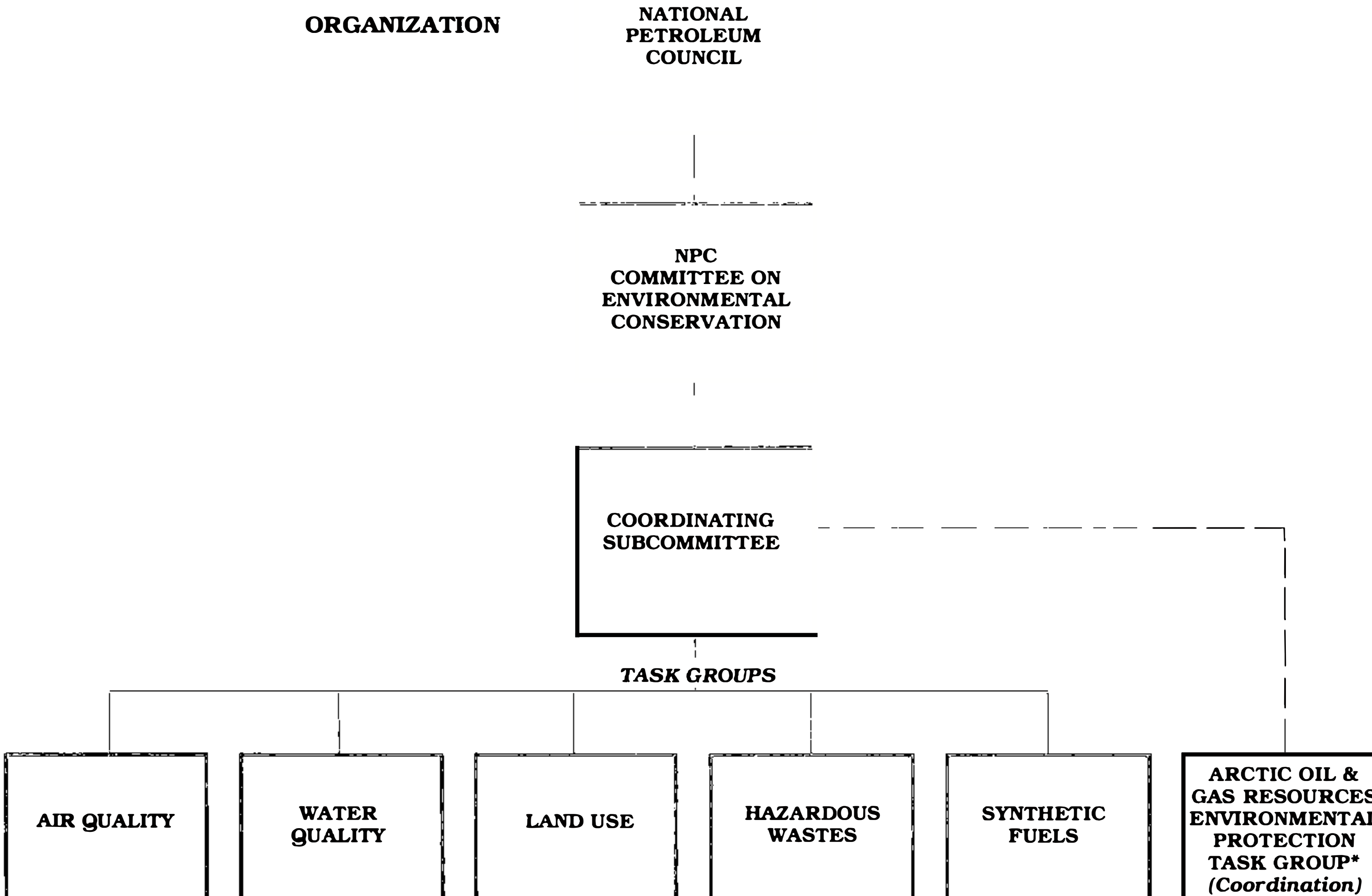

**Reports to Coordinating Subcommittee, NPC Committee on Arctic Oil and Gas Resources*

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ENVIRONMENTAL AND RESOURCE CONSERVATION LAWS
ENACTED BY CONGRESS, 1970-1980

1970 -- National Environmental Policy Act
Clean Air Act Amendments
Water Quality Improvement Act
Water Bank Act

1971 -- Alaska Native Claims Settlement Act

1972 -- Federal Water Pollution Control Act Amendments
Coastal Zone Management Act
Environmental Pesticide Control Act
Noise Control Act
Marine Mammal Protection Act
Marine Protection, Research and Sanctuaries Act
Ports and Waterways Safety Act

1973 -- Endangered Species Act

1974 -- Safe Drinking Water Act
Energy Supply and Environmental Coordination Act
Energy Reorganization Act
Deepwater Port Act
Water Resources Development Act
Forest and Rangeland Renewable Resources Planning Act
Eastern Wilderness Areas Act

1975 -- Energy Policy and Conservation Act

1976 -- Federal Land Policy and Management Act
National Forest Management Act
Toxic Substances Control Act
Energy Conservation and Production Act
Coal Leasing Act Amendments
Resource Conservation and Recovery Act
Fishery Conservation and Management Act
Land and Water Conservation Fund Act Amendments

1977 -- Surface Mining Control and Reclamation Act
Clean Air Act Amendments
Federal Water Pollution Control Act Amendments (Clean Water Act)
Soil and Water Resources Conservation Act

1978 -- Outer Continental Shelf Lands Act Amendments
Endangered Species Act Amendments
National Parks and Recreation Act
Clean Water Act Amendments

1979 -- Emergency Energy Conservation Act
Safe Drinking Water Act Amendments
Water Bank Act Amendments

1980 -- Alaska National Interest Lands Conservation Act
Comprehensive Environmental Response, Compensation and Liability Act of 1980
Solid Wastes Disposal Act Amendments
Used Oil Recycling Act of 1980

COMMENTS ON SYNTHETIC FUELS AND THE ENVIRONMENT

PREFACE

This report was prepared in response to the Secretary of Energy's request that the National Petroleum Council (NPC) update its 1971 report entitled Environmental Conservation -- The Oil and Gas Industries (see Appendix A). Synthetic fuels industry processes were, of course, not discussed in that report.

The NPC recognizes the importance of including synthetic fuel (synfuel) operations in this update. The nation is on the verge of a new energy era, in which alternate sources will begin increasingly to replace conventional oil and gas supplies. The petroleum industry, with its established technological base and facilities, will play a key role in the development of these alternate sources and will have to deal with the associated environmental problems.

The NPC also recognizes that the synthetic fuels industry is just entering the commercialization stage; therefore, an overall assessment of this rapidly changing industry could not easily be accomplished within the same time span allotted for an assessment of the mature conventional petroleum industry. Thus, this appendix is not intended to serve as a comprehensive description of the impact of the synthetic fuels industry on the environment, nor of the impacts of environmental legislation and regulations on the industry. Rather, it seeks to lay the groundwork for any future studies on this subject which may be undertaken. Specifically, the appendix:

- Identifies the principal areas of concern with respect to synfuel development
- Considers the principal analyses on the subject
- Presents recommendations for improvements if similar analyses are undertaken in the future.

The NPC's analysis is based on a review and assessment of the assumptions, methodology, and conclusions of the June 1980 U.S. Department of Energy (DOE) report entitled Synthetic Fuels and the Environment, a recent comprehensive report evaluating the environmental concerns associated with synfuel development. While an extensive literature search was conducted and other reports were evaluated, none were found to have the depth and wide coverage of the DOE report. The NPC recognizes that any report on a rapidly developing industry is quickly rendered out of date by changes in technology, regulations, and other factors. The Council believes, however, that a review and assessment of the DOE effort can identify areas of improvement in organization, data collection, and

analysis that may be helpful in future assessments. It is to this end that this appendix is presented.

SUMMARY AND CONCLUSIONS

The Council determined that, in general, the DOE report Synthetic Fuels and the Environment presents a useful, objective analysis of the impact of synfuel development upon the environment, and the concurrent impact of environmental regulations on the rate and extent of industry development. However, in light of the rapidly evolving technologies and changes in legislative and regulatory controls, there is no doubt that the DOE report is dated. Certain subjects were omitted or insufficiently covered in the DOE report, including:

- The role of state and local governments
- Environmental research conducted by industrial laboratories
- The comparative environmental impacts of synthetic fuels relative to the conventional petroleum industry and other industries
- Human health concerns and protective measures.

With respect to broad issues raised by the DOE report, the NPC concluded that:

- All synthetic fuel development is improperly divided into two time frames: research and development (R&D) from 1980 to 1985, and commercialization from 1985 to 1990. In fact, the timetable will vary widely among the various synfuel technologies.
- The report correctly states that first generation plants require close environmental scrutiny. However, this greater knowledge should be used not only to assure the adequacy of environmental controls, but also to avoid unnecessarily severe controls.
- The DOE report states that new major regulatory constraints are unlikely to emerge. While this may be true, the DOE report overlooks the cumulative effect of numerous small, site-specific constraints, which cause lengthy delays. The NPC believes that the DOE report's estimates of 24 to 36 months for permit acquisitions are overly optimistic.
- The DOE report implies that smaller plants are more advantageous than larger scale plants. This is not necessarily true. There will be many cases where large plants offer cost and control advantages over small plants.

With respect to specific technologies, the NPC found the following principal areas of disagreement:

- In the case of oil shale, the DOE report improperly groups the various techniques together, although each of the mining and process options has unique environmental characteristics. The section on the disposal of spent shale does not adequately acknowledge the large amount of research conducted on this subject nor the current state of knowledge. The DOE report also indicates that zero wastewater discharge will be generally practical. Although it will be practical in some instances, practices will vary from project to project.

- In discussing coal conversion, the DOE report again improperly groups disparate technologies. Coal gasification and associated indirect liquefaction processes differ greatly from direct coal liquefaction.

- The DOE report places undue emphasis on alcohols derived from biomass and urban waste conversion. The future production of alcohols from these processes could be dwarfed by the amount of alcohols and alcohol-derived fuels manufactured by coal gasification, which deserve greater attention. The environmental impacts of biomass and urban waste conversion are also dissimilar and should be treated separately.

The following findings involve environmental issues common to all synfuel technologies:

- Worker safety and health problems have been studied far more extensively than is indicated in the DOE report. Many of these problems have already been encountered and controlled by existing industry practices, and others unique to the synthetic fuels industry are being carefully investigated by industry, government, and other groups, notably the National Institute for Occupational Safety and Health.

- Although the report recognizes the importance of socio-economic questions, it fails to recognize the efforts made by industry to alleviate socio-economic impacts of development.

- The DOE report attempted a comprehensive, regional analysis of all factors affecting site selection. Although it provides a useful insight into the complex problems involved, it project an unwarranted degree of precision. Too many uncertainties exist to allow meaningful conclusions to be drawn, especially in the area of air impact analysis where no generally applicable models exist.

- The NPC believes that the standards that apply to conventional plants should also be applied to synfuel facilities. The choice of project-specific control technology is a

complex function of many individual factors. During technology development, effective uniform performance standards would be difficult to develop. Case by case engineering review and assessment of control performance acceptability has been an effective part of the current regulatory system.

- The DOE report correctly states that biological monitoring and health effects testing will be necessary for synthetic fuel development. However, the large amount of such work already completed or under way is not recognized. In addition, the mitigating effects of product upgrading on toxicity are not mentioned in the DOE report.

While the need for additional reports at this time is questioned, the NPC recommends that, should additional reports be undertaken, the scope of the analyses be briefer, issue-oriented, or site-specific, rather than all-inclusive. Separate analyses would avoid the treatment of dissimilar problems as equally critical, and a clearer knowledge would be gained of the particular needs of each technology.

Improved data sources now exist, many of them site- or process-specific. These sources include private research, permit applications, monitoring information, and government reports. Utilizing available site-specific data is recommended as it was observed that many, if not all, of the impacts of synfuel development will be felt primarily in the state and local communities where the facilities are located. Attempts to accommodate the communities involved result in differing permitting times and conditions, levels of public acceptance, types of environmental controls needed, and socio-economic impacts.

COMMENTS ON THE DOE REPORT

DOE Report Content and Coverage

Preparing a comprehensive review of all environmental information and issues for such a widespread and rapidly evolving field as synfuels development is a monumental task. The DOE document attempted to review environmental concerns and the effect of environmental regulations on the rate of synfuels development. Through no fault of its preparers, the DOE report is already dated. Much relevant data have been developed since the DOE report was published in June 1980 by continuing environmental research and control technology development. In addition, regulations have been issued or interpreted and permitting activities have progressed since the report was published. Obviously, all questions have not been answered or even identified. New problems can arise for broad technologies or specific projects. Some environmental issues discussed in the report as uncertainties have been resolved; others have become more focused

The DOE report also covers insufficiently or omits entirely such areas as:

- The development of tar sands
- The role of state and local governments in the setting of standards of acceptability, permitting and monitoring of compliance, conduct of research, and, most importantly, the receipt, balancing, and implementation of the public's concerns for synfuel development
- The substantial private research on environmental issues found in public literature, in permit applications and hearings on synfuel projects, and available through direct discussions with industry researchers
- Comparisons of synfuel technology and environmental residuals to similar existing activities and impacts, placing this industry in perspective. (Examples of comparable processes exist in petroleum refining and transportation, coal extraction, and electric utilities.)

DOE Report's View of the Synthetic Fuels Industry

Four issues in this area deserve comment: technology, degree of control, health concerns, and local issues.

Technology

Due largely to the federal synfuel development policy at the time of the DOE report, the document improperly divides all synfuel development and commercialization into two discrete stages: one emphasizing applied R&D, including environmental research; and a second stage representing commercial deployment Also, the report assigns the two stages (for all synfuel technologies) to specific time periods: R&D between 1980 and 1985, and deployment between 1985 and 1995. Such simplification is incorrect and misleading. Completion of R&D, culminating in commercialization, cannot be scheduled that precisely. In addition, the timing of commercial deployment depends also on the type of process and its location. For some synfuel technologies (particularly gasohol and low-Btu gasification), commercialization has already occurred. For others, years of work remain.

Degree of Control

The DOE report correctly states that the environmental characterization of the first commercial plant to use each new technology will require an extra level of scrutiny. This better understanding should be used, however, not only to assure the adequacy of environmental controls, but also to avoid unnecessarily severe controls, which could doom an otherwise viable technology. Basically, new synfuel technologies should be regulated to the same level of

hazard reduction and pollution control as are required for new conventional plants.

Health Concerns

An area of concern that is not addressed in the DOE report in relation to its importance involves the health aspects associated with synfuel development. There may be some potential adverse human health effects associated with particular aspects of synfuel products and processes. Therefore, the importance of safe handling procedures, toxicity testing, and/or hazard evaluations should be explicitly recognized. However, as in the case of environmental controls and monitoring discussed above, it is not reasonable or appropriate to apply more burdensome standards of safety to synfuel products and processes than those applied to existing products and industries. Similarly, the costs of these safety and health programs will also have a significant impact on the viability of synfuel development.

Local Issues

In defining environmental constraints to the development of synthetic fuels industries, the DOE report projects no major new regulatory constraints. While this may be true, the report overlooks an even more serious problem. It is likely that numerous small delays will continue to arise at each specific site, which, taken together, will result in a major project constraint. These local or regional problems often involve environmental issues, but are also intertwined with socio-economic, financial, and political issues as well, increasing the difficulty of satisfactory resolution.

Technologies and Environmental Issues

Oil Shale

Overview of DOE Report Coverage. The summary of oil shale technology information and environmental issues in the DOE report is generally complete. However, certain discussions are overly simplistic and opinions regarding some environmental concerns are unsubstantiated. Specific concerns identified by the NPC are presented in the following sections.

Process Technologies. At several points in the document, oil shale technologies are grouped together. Such grouping is not always appropriate. It is important to remember that there are many ways to mine and/or process shale. The stage of development and environmental characteristics can vary substantially for each technology. For example, the brief general process description provided for "Modified In-Situ Oil Shale" appears actually to include true in situ processes as well, since the latter are not specifically covered elsewhere. Some clarification and better descriptions of the different processes are needed here. Also,

product treatment needs cannot be generalized for all in situ produced shale oils nor for all surface retort products.

Pollution Control Options. The report highlights specific pollution control systems. In this type of discussion it should be noted clearly that the choice of the "best" pollution control system is a complex function of the specific technology, project size, operating methods, and shale resource. The actual selection should be part of the plant design phase. The variability that could occur in choosing the best pollution control system should be stated. For example, the DOE report implies that the Stretford process is the only available means of sulfur emission controls. In fact, there are several control options; Stretford is only one of several demonstrated control methods. In many processes, the retort offgas will be oxidized to recover sensible heat and heat of combustion. This will transform hydrogen sulfide to sulfur dioxide, allowing use of any of a number of flue gas scrubbing processes.

Surface Disposal of Processed Shale. The discussion of spent shale disposal implies that little or no work has been completed in this area. Actually, for some of the more advanced projects, considerable research and specific regulatory reviews have been completed. Also, the discussion is out of date as the general regulatory treatment of spent shale has changed somewhat since the DOE report was completed.

For some of the more advanced projects, shale samples have undergone years of study to identify appropriate methods to deposit, compact, cover, seed, fertilize, and irrigate the disposal site to maximize physical, chemical, and ecological stability. Research has shown that through proper compaction, a stable embankment can be constructed that, with proper revegetation, should be permanent against all foreseeable natural forces. Furthermore, supercompaction of the bottom few feet can prevent seepage directly into groundwaters. This procedure, combined with drainage controls and re-use of runoff, will prevent contamination of surface and groundwaters. However, research and monitoring programs to date have dealt with relatively small quantities of shale produced by pilot and demonstration plants. Permeability, erosion, and other effects will require careful monitoring at commercial shale sites. Monitoring and custodial care are recognized by the industry as integral aspects of commercial operations, and will be conducted during the operation and continued after the site is closed down.

On the regulatory side, pending a three-year health hazard study, Congress in 1980 exempted from Resource Conservation and Recovery Act of 1976 (RCRA) regulations all wastes generated from the extraction, benefaction, and processing of ores and minerals. Spent shale and other shale-retorting related wastes are covered by this exemption. Although some samples of spent shale leachate have been tested and do not show hazardous characteristics, it is too early to make a general conclusion.

Water Use and Discharges. In the DOE report summary, it is stated that no absolute environmental constraint appears to exist that would limit development of a particular technology. However, "in situ conversion processes" are said to be among those most susceptible to such an absolute constraint, due to the potential for groundwater contamination. It is not reasonable in this context to lump together all in situ processes. Those processes generally referred to as "true in situ" may involve pressurized injection of fluids into a fractured underground zone. In contrast, the modified in situ shale oil extraction process is carried out with the processing zone under reduced pressure (less than atmospheric).

Regarding water use and discharge, the report states that "under current planning, oil shale developers envision zero discharge of their waste water." This is true only for some projects. It will be workable where mine water is produced in manageable quantities. At the Colony project, for example, wastewater will be treated and internally recycled and re-used. Runoff from irrigation of the spent shale disposal area and natural precipitation will be captured and retained in catchment areas for use in plant operations. No wastewater discharge to surface streams is planned.

In a modified in situ retorting facility, dewatering of the entire mine would necessarily continue until retorting operations had ceased and there was no further risk of pollution of groundwater from leaching of the spent shale. Water treatment systems designed to allow re-use of mine and process water would continue to provide any necessary treatment to water collected in the spent retorts. Major objectives would be to maximize re-use of water, and to use re-injection as a primary means of disposal of any excess water.

Worker Health and Safety. In the DOE report, it is stated that the work environment is "largely uncharacterized" and that "controls and procedures are not defined " In fact, the majority of the occupational risks that are associated with oil shale development are very similar to those found in conventional construction, mining, and refining activities. Possible adverse effects will be eliminated or mitigated by procedures which have been proven effective in existing operations

Occupational hazards include dust and noise exposure from mining, crushing, and materials handling operations. Incorporation of engineering controls and worker isolation in sound insulated, air conditioned, and air filtered enclosures when necessary will reduce occupational exposures to less than those specified by the Occupational Safety and Health Act and the Mine Safety and Health Act.

The risk from any carcinogenic materials in shale oil or its products will be controlled by applying techniques already practiced in the mining and petroleum industries. Worker protection is maintained by well-developed industrial hygiene procedures designed to protect employees from exposure to toxic materials. Protection

of the general public is accomplished through the processing steps needed to convert raw materials to finished products, which can reduce the toxicity of the products. For example, data are available that indicate that the biological activity of shale oil can be reduced through hydrotreating. Thus, the effect of various processing techniques on product toxicity is likely to be an area of further study.

Industry and government have sponsored numerous studies to determine the health hazards associated with oil shale processing and the resulting products and by-products. These studies have been published in scientific journals and books and presented at numerous symposia.

Product Characteristics. The DOE report indicates that biological monitoring and health effects testing will be a necessary part of the development of shale oil products. The NPC agrees and recognizes the importance of such work not only for shale oil products but for all synthetic fuels. It should be noted, however, that much work in this regard has already been completed and that more is ongoing or planned. Groups that have been involved in these product evaluations in addition to private industry include the American Petroleum Institute, the Department of the Navy, the Environmental Protection Agency (EPA), and DOE.

Socio-Economic Impacts. The DOE report identifies socio-economic impacts as major concerns for oil shale development, and the NPC agrees with this view. Unfortunately, the efforts made by industry to alleviate the socio-economic impacts of development were not adequately recognized in the report. Several oil shale projects have been designed by their sponsors as models to demonstrate the commercial viability of oil shale development and to provide convincing, practical evidence of its compatibility with the highest standards of socio-economic planning. For example, in 1974, the Colony Development community development staff conducted extensive discussions and negotiations with Garfield County, Colorado, officials with respect to appropriate zoning resolution. A resolution was adopted in 1975 and amended in 1980 which approves a mixture of land uses and ranges of housing densities consistent with the local 15-year master plan. The resolution should enable Colony to provide adequate housing and sufficient flexibility to react to any unexpected increases in employment population projections and has resulted in the new planned community of Battlement Mesa.

Coal Gasification and Indirect Liquefaction

Overview of DOE Report Coverage. Coal gasification and indirect liquefaction technology is undergoing rapid and substantial development, including several processes that are identified in the DOE report. Therefore, some of the process limitations described in the report are no longer valid. For instance, caking coal has recently been successfully used in a modified Lurgi gasifier, and

the pilot Texaco process mentioned in the DOE report is now commercial.

The DOE report raises but does not discuss possible solutions to the potentially adverse impacts of solid waste generation, the extent to which pollution controls should be employed, and the potential health and safety hazards from coal gasification. The following sections emphasize that much more information and actual experience exists in industry for tailoring control technologies to the degree of hazard, and for addressing health and safety concerns, than is apparent from reading the DOE report.

Process Technologies. For clarity, coal gasification and indirect liquefaction should be separated from the distinctly different direct coal liquefaction processes. Indirect liquefaction requires products from one of the several commercially available gasification modes, so it should be discussed in conjunction with them. It is important to note that different gasification processes can be linked to the various liquefaction options to meet the objectives of the project sponsor.

Any comparison of processes or their environmental impacts such as shown in Table 3-1 of the DOE report should be carefully made. The coal gasification data entries (Fischer-Tropsch and Lurgi Dry Ash) appear reasonable, but they could be significantly different depending upon the choice of technology or coal used. The Fischer-Tropsch entry should have identified the gasification process used. Improper use of the presented data could lead to the erroneous preference for one process over another. Commercially available controls, for instance, can reduce the sulfur oxide emissions of a Lurgi Dry Ash plant to the range of 10 tons per day (as indicated in the table for a Fischer-Tropsch plant). The table should have noted also that air emissions from gasification processing units per se have only a small potential impact on air quality degradation. The major air impact is more likely to be emissions from the plant heaters, boilers, ancillary equipment, or coal-fired powerplant serving the facility. Any environmental analysis should clearly reflect this. Additionally, although the table is normalized to 50,000 barrels per day of crude oil equivalent, it would have been useful if specific product outputs were given (e.g., thousand cubic feet of gas, barrels of methanol or gasoline).

The DOE report indicates that the Lurgi process requires noncaking coal, but recently a Lurgi gasifier has been developed with an appropriately designed stirrer, which has gasified even strongly caking coal.

Because coal gasification technology is rapidly changing, it was impossible for DOE to produce a report representing current "state of the art" technology. For instance, Table 3-1 would more accurately compare current synfuel technologies if it included data on the integrated gasification combined cycle mode of electric power generation. As an example, based on the current design of the Cool Water Plant (California) and normalized to 50,000 barrels

per day of crude oil equivalent, the comparative data are as follows:

- Process -- Integrated Gasification Combined Cycle Power Plant (Cool Water Plant); and Texaco Coal Gasification Process (1,327 megawatts of electricity)

- Input -- 11,800 tons/day of bituminous coal at 12,300 Btu/lb and 0.48 percent sulfur

- Coal to Busbar Efficiency -- 37.5 percent

- Water Requirements -- 18,000 acre-ft/yr (based on 0.5 gal/kwh)

- Air Emissions with controls:

    - Sulfur oxide -- 5.3 tons/day

    - Nitrogen oxide -- 19.8 tons/day

    - Carbon monoxide -- less than 3.4 tons/day

    - Hydrocarbon -- 0 tons/day

    - Total Suspended Particulates -- 0.7 tons/day

    - Carbon dioxide -- 30,000 tons/day

- Solids:

    - Slag -- 1,300 tons/day

    - Sulfur -- 57 tons/day

Coal Gasification Solid Waste Disposal. Coal processing and use, including conventional direct burning of coal, will always yield a solid waste. Its disposal is not a unique impact of coal gasification. Proper handling must be addressed no matter what the origin and requires information on the amount, degree of hazard, and geographic concentration of the waste. The amount can be calculated, and the report correctly identifies the need to determine its hazardous potential. With this information, an environmentally sound disposal facility can be constructed using accepted engineering practices. It should be emphasized that a large coal gasification plant could be located in a sparsely populated area, which may represent an environmentally advantageous way to accumulate coal waste materials. In this way the material may be concentrated and managed with greater control and less impact than if it is dispersed in a multitude of coal-fired powerplants located in congested areas.

The DOE report properly emphasizes that hazardous wastes produced from catalysts, treating chemicals, and heavy metals may

also be present and that there are accepted methods of handling these materials. In addition, under RCRA there is a developing regulatory scheme to assure proper handling of these wastes.

In summary, wastes can and should be carefully tested for their hazard potential and disposed of according to current well-understood high-quality engineering practices.

Control Technology. The DOE report summary implies that stringent control technology including Lowest Achievable Emission Rate (LAER) is required to reduce the degree of risk. As a rule, emission and effluent controls should embody accepted Best Available Control Technology (BACT) and New Source Performance Standard controls where identified. These have been established to produce the desired benefit with due consideration of the feasibility and cost. The degree of control should always be in concert with the extent of the hazard. Controls that are more than sufficient to abate the hazard are not appropriate or cost effective. Should effluent evaluation and testing identify critical hazards, however, the lowest control level may be the only acceptable rationale. This regulatory approach has often been used to control suspected carcinogens in the refining and chemical industries.

Worker Health and Safety. Worker health and safety and public health is of paramount interest to industry and the general public. The concern expressed in the report about the many unknowns in the synthetic fuels industry is appropriate, including the special emphasis on the carcinogenic potential of synfuel intermediates and products. However, similar concerns have been addressed successfully in other industries Synfuel development does not introduce new phenomena but rather new configurations of a set of manageable events. Of course, it is anticipated that some new control techniques may need to be developed. All process streams and products deserve the careful scrutiny emphasized in the report to assure that informed control and handling decisions are implemented.

Even with the best of intentions, engineering design or operation errors and problems mentioned in the report may occur. Every industry has had this experience. The proper response is to minimize errors and develop the appropriate training, contingency plans, and emergency procedures should problems occur.

The report claims that a large-scale plant provides a potential for increased risk over a smaller facility. A case can be made that large plants spread over a large area would reduce employee and public exposure to hazardous chemicals and be able to support an adequate on-site safety and industrial hygiene staff, which would further reduce employee risk exposure.

The DOE report concentrates on the potential harm from carcinogenic, mutagenic, or teratogenic properties of synfuel intermediates or products. It barely mentions conventional health and safety hazards and it is arguable that there may be a greater

potential for employee harm in these areas. The DOE report should place more emphasis on important conventional impacts resulting from such incidents as fire, explosions, slips, and falls.

Coal Mining Impacts. The DOE report correctly emphasizes that coal mining-related health and environmental effects will represent a substantial portion of the total synfuel impact assessment. These effects should be placed in perspective, however, since they will occur as our coal resources are developed to meet the nation's energy needs, regardless of end use. More importantly, coal mining is already governed by strict safety, health, and environmental laws and regulations. Past recognition of these impacts by the coal-mining industry has caused development of appropriate control strategies.

Air Quality. The DOE report correctly emphasizes that ancillary fuel-burning equipment or an auxiliary powerplant serving a synfuel project may be the main source of criteria pollutants. These emissions will be handled like those from any other emitting industrial facility. It is important to understand, however, that the Prevention of Significant Deterioration (PSD) review and the (Class I area) visibility constraints may create severe and possibly insurmountable barriers to specific synfuel projects. Class I increments are so small they could easily be consumed by the first plant sited to develop a geographically concentrated coal resource. Moreover, a project located many miles from a Class I area may not be permitted if the plant has an impact on the area's integral vista. It is difficult to judge at this time the significance of these constraints, because they are under consideration for change in future amendments to the Clean Air Act.

Coal Liquefaction

Overview of DOE Report Coverage. Some of the emissions data used in Chapters Three and Five of the DOE report for major coal liquefaction technologies are outdated or incomplete. For example, the DOE report utilizes Exxon Donor Solvent (EDS) plant emission estimates published in a 1979 study by SRI International. At the time of publication of the DOE report, the emissions data used were probably the best available, but technology developments in the past two years will have an impact on some of the DOE conclusions based on the earlier data. Recently revised emission estimates for an EDS plant have been prepared and have been issued in an updated study design prepared for DOE. The DOE report also includes some inappropriate recommendations regarding types and degrees of pollution controls, as well as comparisons among synfuel technology emissions.

Process Technologies. The initial commercial coal liquefaction units should not require special controls, as stated in the DOE report, beyond those needed to meet acceptable environmental constraints. In particular, the first commercial units should not be

designed for minimum environmental impact, if this concept presumes LAER technology rather than BACT. A more practical approach would be to conduct a risk assessment to determine if a coal liquefaction plant, after meeting existing environmental regulations, still presents unreasonable hazards to human health and the environment. Only if a positive finding were made would additional controls be warranted. While the need to minimize environmental impact should be a major concern, consideration must also be given to economic practicality. For example, consideration of economics is the principal intent of the BACT review in the PSD permit process. All pollution control measures carry a cost, of course, but the imposition of unnecessary steps would decrease the likelihood of achieving an economically viable synthetic fuels industry.

Synfuel Technology Comparison. As discussed earlier, the comparison among different synfuel technologies presented in Table 3-1 of the DOE report must be carefully drawn. For example, the emissions and water requirements have been invalidly normalized to a common plant size. Such quantities are not necessarily directly proportional to plant size. In addition, obvious discrepancies in sulfur content of the raw materials are not corrected.

Solid Waste. Overall, the statements made concerning the quantity, quality, and sources of solid wastes expected from the EDS process are accurate. Two types of wastes should be generated. One group (ash, fly ash, and liquefaction bottoms) is expected to represent the major volume of wastes generated. Based on the May 19, 1980, RCRA guidelines and upon available data, these EDS solid wastes are currently considered nonhazardous. The other source of solids would be generated from the treatment of the process wastewaters. The petroleum and chemical industries have had extensive plant experience in treating these wastes, as is recognized by the DOE report.

Wastewater. The report correctly states that the process wastewaters can be treated by present technology. For example, the EDS design now includes phenol extraction followed by biological oxidation that will reduce phenol concentrations to acceptable state levels. The DOE report concluded that state phenol standards in Illinois could be a major siting constraint, which is no longer true.

In addition to those compounds mentioned by the DOE report, process wastewaters are also expected to contain organic acids, ketones, and aldehydes. The streams may also contain trace levels of cobalt, chromium, copper, manganese, molybdenum, selenium, tin, and zinc.

Dissolved air flotation should also be listed as a water pollution control option for the treatment of organic species in wastewaters. In addition, particular emphasis will be placed on landfarming as a control option for waste treatment sludges; incineration is also under consideration.

Air -- Comments on Air Pollution Control Technologies. Hydrotreatment of process offgases to control nitrogen oxides is recommended by the DOE report. This recommendation is unclear in terms of which process of gases are of concern and how "hydrotreatment" could be used to control the nitrogen oxide emissions contained in these offgases. Flares should be included as control equipment options for hydrocarbon and carbon monoxide emissions in process releases.

The specification of baghouses to control total suspended particulate emissions in tail gases is questionable as the particulate loading in sulfur plant tail gases is not a concern.

Biomass and Urban Waste

The report places greater emphasis on alcohols derived from biomass and urban wastes than it does on methanol and methanol-derived gasoline from coal-derived synthesis gas. This emphasis does not place these two source categories in proper perspective to their relative potentials for replacing petroleum transportation fuels. Alcohols from biomass and waste sources are making a small but important contribution to the nation's transportation fuel supply, but only coal-derived alcohols have the potential to replace large amounts of petroleum-derived fuels.

In addition, the environmental impacts of the two source categories (coal-based and biomass) are quite different, and separate discussions are justified. For example, the impacts of coal-derived alcohols are in large measure those of coal gasification. On the other hand, as the report correctly identifies, the biomass fuels industry is regional, characterized by many relatively small plants, and has principally local environmental impacts, mainly on soil erosion and water quality.

The actual significance of these environmental impacts is difficult to assess because the report gives no indication of the net energy production of the biomass industry. For any synfuel project, the acceptability of environmental impacts depends in part on the net production of petroleum substitutes. This is especially important in the biomass area because of the large amount of processing energy required, which may exceed the energy value of the product.

Any future environmental impact analysis of synthetic fuels from biomass and waste sources also should survey: state and local permit data for specific projects, available data from actual plant operations, emerging EPA Pollution Control Technology Guidance Documents, and EPA- and/or Department of Agriculture-sponsored studies of on-farm alcohol production facilities.

Regulatory and Environmental Impacts in the DOE Report

General

Chapters Four and Five of the DOE report contain most of the regulatory and environmental analysis. The discussion is understandably lengthy and complicated; a brief summary of the conclusions placed at the front of the discussion would be helpful. The report attempts to interrelate such factors as air quality, water availability and quality, socio-economic assimilative capacity, ecological disturbance, and state and federal regulatory constraints into an overall regional assessment for the synthetic fuels industry. It is believed, however, that the lack of precision of the many premises hinders meaningful conclusions. Nevertheless, the report does present a unique insight into the many environmental factors affecting the development of a synthetic fuels industry.

A sense of uncertainty affects every aspect of the synfuel development program. Uncertainty is the common factor in this section of the report, involving the technology, economics, and environmental controls, and is strongly apparent in the discussion of the "rules of the game;" i.e., regulatory, socio-economic, and political constraints The cumulative effect is delay, because each uncertainty requires time to resolve and defers achieving the national goal of developing domestic energy resources.

The comments of the NPC on the regulatory and environmental impacts chapters of the DOE report may be summarized into the following categories:

- The NPC criticizes the use of the air quality models on a regional basis. These models are generally recognized by those skilled in the art as being only gross approximations even on a site-specific basis. In addition, the maps imply an accuracy that is not warranted (although recognized by the authors as gross approximations) and could lead to misinterpretations.

- The Phased Development Proposal implies that commercial plants should be held back four to six years for further research and development. However, some projects are already in the planning and development stage preceding commercialization. Their developers have examined the risks and uncertainties still remaining after R&D and are ready to commercialize. The amount of money already committed is evidence of their belief that the uncertainties have been reduced to a point where a technically and economically viable plant can be built that will offer acceptable safety and environmental protection to worker and public alike.

- There is an implied recommendation for smaller-size plants (28,000 to 35,000 bbl/day) vs. larger plants (100,000 bbl/day). This should not be a general recommendation.

Individual technologies benefit differently from scale-up factors and this could outweigh the disadvantages caused by the greater resource requirements of a larger plant.

- The DOE time estimates regarding permitting procedures, together with the need for Environmental Impact Statements (EIS), do not appear realistic. The DOE permitting estimates of from 24 to 36 months should be construed as minimums when everything goes smoothly, but this is seldom the case. The report properly recognizes that new procedures to facilitate permitting would be helpful, especially for large projects. Synfuel projects could be permitted in a timely fashion within the current regulatory framework, but only with proper coordination of all concerned.

- The subject of health and safety in the synthetic fuels industry was not treated as extensively as needed in the report.

Air

As described in the DOE report, the relative ease of siting synfuel plants in some locations compared to others is based on speculative modeling analysis and implies an accuracy and finality that is unjustified. The detailed discussion in the report, together with the maps and charts, indicates a greater confidence in the conclusions of the study than can be supported. The overall need for this detailed analysis based on hypothetical assumptions, assumed or average data, and generalized plant design and terrain is seriously questioned. For instance, it is admitted in the report that "flat terrain was assumed for most cases." Since many of the potential synfuel development areas are located far from flat terrain, this assumption can lead to a serious misstatement of potential air quality constraints. The analysis of the modeling results showing the variation in ambient impact with varying stack heights (Table 5-5 of the DOE report) does not provide "additional insights into the effects of irregular terrain," as stated. Terrain effects must be studied on a case-by-case basis.

In the section on PSD Air Quality Permits it is stated "the third PSD requirement is that allowed regional ambient air quality increments not be exceeded. In an area where the air is relatively clean, this requirement becomes less restrictive than where the air is relatively polluted." This statement is incorrect. The increment system is designed to make requirements more restrictive in Class I (relatively clean) areas and less restrictive in Class III (relatively polluted) areas. Class II and III areas can only be more restrictive if the total increment is not available because pollutant concentrations approach federal ambient air quality standards. In this section it is also stated that:

> In the process of obtaining these data, the proposed source owner may discover that the air quality is worse than anticipated and that the plant must, therefore, be downsized, sited elsewhere, controlled further, or cancelled. It is possible that the data will demonstrate that the area is in non-attainment of standards, causing significantly increased restrictions.

Although possible, such an occurrence is most unlikely.

Revisions to PSD regulations are referred to as "yet-to-be-developed," and some still are. However, revised PSD regulations issued in August 1980 state that estimated amounts of fugitive dust emissions need not be included with other mine particulate emissions to determine if the 100 tons-per-year standard for PSD applicability will be exceeded. The Set II pollutant requirements are still to be proposed as of June 1, 1981.

Water Use and Quality

The DOE report cites zero discharge as a pollution control option. The EDS Wyoming Study Design, as of June 1, 1981, calls for zero discharge. This is the result of the hydrological constraints of the region and not of the advantages of zero discharge as a water pollution control option. In regions where high-quality major water resources are readily available zero discharge may represent an unnecessary and thus unacceptable pollution control option because of the added economic burden.

The DOE report's use of the volume of free flowing water as the measure of availability, as opposed to water in storage or water collected through mine dewatering, is inappropriate in arid regions. Certainly, the annual periods of low flow would require that any synfuel plant have a reliable year-round source of water.

The report states:

> Western water law tends to constrain the use of water for energy production processes, including energy facility cooling processes. State law, rather than federal law, dominates the determination of water rights, and a state official (often the State Engineer) is responsible for issuing permits for valid water use. The permits grant priority to water uses based on classes of beneficial uses and the date of the issuance of the permit.

This statement is untrue in Colorado.

Although eastern water policy differs from western with respect to riparian rights, each state would have to be evaluated independently. For example, New Jersey has ownership rights to both surface and ground waters. Therefore, any application for water diversion would involve a state permit, similar to that required by western states' policies.

Coal Mining Impacts

The discussion on coal mining impacts should be expanded to include a discussion of the mitigating effects which will result under the Surface Mining Control and Reclamation Act (SMCRA). It is anticipated that there will be some major administrative changes in the SMCRA regulation and permit procedures. Further, the environmental impacts are not unique to the synthetic fuels industry but occur in the general use of coal.

Solid Waste

It is recognized that the nation's vast energy sources in coal, oil shale, and tar sands contain large volumes of nonhydrocarbon matter that become a solid waste. Constituents in the original energy resource will be present in this waste and can include a wide range of elements, depending at least in part on the specific feedstock. The examples shown in Chapter Five should be construed as representing only typical compositions of specific coal residues.

The NPC is aware of the magnitude of the solid waste problem and agrees that it must be handled in an environmentally acceptable manner. Comments on the report in this regard may be summarized as follows:

- Post-June 1980 changes in RCRA implementing regulations are not included.

- As mentioned earlier, solid wastes from coal and oil shale operations are currently subject to a broad exemption from regulation under RCRA; however, final regulations may change that classification. The report correctly identifies a major uncertainty concerning the classification of synfuel waste into hazardous or nonhazardous categories, which has a significant impact on timing, cost, and site selection.

- Although the NPC recognizes that synfuel waste disposal generates unusual problems in volume and to some extent in composition, they are problems that can and will be managed. Many other problems are not new and have been addressed during many years of industrial experience; thus the knowledge gained in older but related industries will be applicable. In addition, the extensive testing and development work on synfuel waste streams being undertaken by government, academia, and industry is continuing to add to that knowledge.

- The difficulty in obtaining approved disposal sites for both nonhazardous and hazardous wastes is not emphasized. Siting is rapidly becoming a serious problem for industry in general and will certainly be a major factor in the synthetic fuels industry.

Health and Safety Concerns

Previous discussion in this report has emphasized that the health and safety related issues will pose some of the most important and difficult questions to be resolved by the synthetic fuels industry and the public in general. The DOE report recognizes that one of the most critical factors surrounding the synthetic fuels industry is the regulatory and health effects uncertainty and its potential dampening effect on development.

Regarding the existing laws and/or regulatory agencies that address health and safety concerns in the synthetic fuels industry, the DOE report listing is incomplete. All of the following laws or the regulations issued under them can be used to focus attention on any health and/or safety problem that could arise, whether of a public health, worker protection, or product safety nature.

- Clean Air Act, primarily under Sections 108, 109, 111, 112, and through EPA's policy document to control air carcinogens
- National Emissions Standards Act (Title II of the Clean Air Act), primarily under Sections 202, 211, 231, and 303
- Clean Water Act and Federal Water Pollution Control Act
- Safe Drinking Water Act
- Resource Conservation and Recovery Act
- Toxic Substances Control Act, particularly Sections 4, 5, 6, and 7
- Occupational Safety and Health Act
- Mine Safety and Health Act.

In addition to these statutes, the Federal Hazardous Substances Act, the Consumer Product Safety Act, and other laws administered by the Consumer Product Safety Commission could be used, on the basis of health concerns, to regulate various aspects of the synthetic fuels industry and/or its products. In particular, the Toxic Substances Control Act grants very broad authority to EPA for the regulation of any chemical substance produced in the synthetic fuels industry. Similarly, the Occupational Safety and Health Act and the Mine Safety and Health Act provide very broad authority for the regulation of occupational hazards.

Thus, while there are certainly unknowns or uncertainties associated with synfuel products and processes, there are existing laws that could control them if necessary. However, the existence of these broadly structured statutes adds to the uncertainty that developers face since the lack of regulatory restriction or control today is no guarantee that such constraints will not be added later. This dual uncertainty is not emphasized in the DOE report.

Likewise, the DOE report does not recognize that the accurate assessment of possible health effects associated with the synthetic fuels industry and its products is a continuous process and is complicated by the developing nature of health science technology, the possible interactions with other substances, and the effects of differences in lifestyles.

The DOE report ignores the difficult but necessary task of balancing risks and benefits. At each stage of development a concensus judgment that balances the inevitable health and safety risks must be weighed against the national benefits of synfuel development.

Socio-Economic Impacts

The DOE report recognized the importance of socio-economic impacts due to the development of synthetic fuels. A single commercial-size shale oil operation will employ as many as 2,000 to 3,000 people. Injection into community life of these workers, their families, and the people who will serve them would cause serious readjustments in existing cities of considerable size. If the influx occurs in an area where there is no town, or where existing communities are small, such as in the Piceance Basin of Colorado, the growth can be overwhelming.

This growth can cause cash flow problems for the local communities and states. A significant amount of aid, previously expected from the federal government, is not likely to be forthcoming.

Local and state governments have other alternatives, however. Western states like Colorado and Utah receive royalties from federal land resource development; 37 1/2 percent of these funds are earmarked for roads and schools. An additional 12 1/2 percent was earmarked a few years ago for energy impact assistance, although oil shale trust fund monies are not oriented toward such impact aid. Distribution of these funds could be made more equitable. Also, states impose equal borrowing limits on their counties and townships for community improvements, regardless of the contribution of those counties and townships to state revenue and the impacts they sustain thereby. These limits could be increased or weighted to recognize these contributions and impacts. For example, in Colorado there is a limit of $200,000 per county, yet Rio Blanco County, Colorado, was the site of minerals production for many years, sufficient to make $12 million per year in mineral royalties. The state limits are more restrictive than federal law, however, which gives the states authority to distribute one-half the leasing and royalty funds to the counties where the values rise and the impacts are most severe.

The federal government can provide for facilitating transfers of federal land needed for community development. The individual transfers should be of sufficient size to prevent skyrocketing of

land prices as the community expands beyond its original boundaries to private lands.

State and local governments can develop systems for corporate prepayment of taxes. This mechanism should probably include utilities, construction companies, and other groups that must participate in growing communities.

An example of community planning for oil shale development areas is Battlement Mesa, a totally new community under construction near Parachute, Colorado, in Garfield County, Colorado. It is being developed as a joint venture of the owners of the Colony Development oil shale project. It will be an "open" community rather than a company town. It will be a complete community, with the following land uses:

Land Use	Percentage
Residential	
Schools	
Churches	
Commercial/Office	
Golf Course	
Community Open Space	25
Arterial & Collector Streets	4
Total	100

Residential	Units
Mobile Homes	1,000
Single Family Homes	2,800
Town Houses	2,100
Apartments	1,400
Total	7,300

Other corporations are participating at other locations. Some are contributing a share or are funding employment of town personnel. Some are building housing. Some are guaranteeing income from new housing until amortization of the cost is complete.

Site Selection

The DOE report attempted the most comprehensive analysis of factors involving site selection in the emerging synthetic fuels industry. The incorporation of analysis of air quality, water availability and quality, socio-economic assimilative capacity, and ecological disturbance, together with state and federal regulatory constraints, into a regional basis is unique. It provides an insight into the complex problems involved in siting. Data coverage, while somewhat out of date today, is representative of the type of problems that must be addressed. As such, it provides a valuable service.

However, the attempt to link all of these factors together to present a regional synfuel impact study infers a far more precise analysis than is warranted. This does not imply that the authors were not making reasonable value judgments, but simply that it is a nascent industry, with technologies and costs not yet completely defined, with a regulatory framework (both state and federal) that has not been fully implemented, and with social and political pressures that are not well understood. These factors, together with the use of models and assumptions, all of which are subject to error, result in a cumulative uncertainty that makes the presentations meaningless. In fact, the report states, "It is fair to say that a developer of the combination maps could use any of a nearly infinite set of combinational rules and get quite different regional displays."

The NPC appreciates the difficulty and understands the degree of accuracy of the presentation, but is concerned that the conclusions derived from the presentation may be misleading. Specific comments are summarized as follows:

- It is stated that environmental influences may preclude "attractive sites from plant siting considerations." Indeed there may be instances where environmental restrictions may eliminate a site, but site selection is based upon three factors -- engineering feasibility, economics, and environmental considerations. Many of the environmental restrictions are interrelated with economic and engineering feasibility and cannot be evaluated without considering them all. As an example, most of the synfuel conversion processes require water not only for cooling, but as a raw material for conversion. The state's right to apportion water supply cannot be considered solely environmental, as there are socio-economic implications to that regulation. Hence, if water cannot be satisfactorily obtained in sufficient quantities, the site is not eliminated solely on environmental grounds, but rather on a complex interrelationship of environmental, economic, social, and engineering feasibilities.

- Although state relationships are presented in the report, it is important not to underestimate the influence of the state's requirements in the development of synfuel operations. These requirements contain broad bases of legislative actions ranging from tax structure to environmental regulations. Moreover, during public hearings, public awareness and interaction play a decisive role in the pattern and duration of permit acquisition. Usually these hearings are the first public forums where positions for or against the project start to take form.

- The section on resource areas is useful for defining coal resource geography but its overall use for siting is questioned.

- The reference to large coal-burning facilities is unclear. There is no discussion of the relationship between the potential for synfuel siting and the impact that Class I areas will have on large coal-burning facilities except for reference to Table 5-10, which verifies that the increased emission levels due to synthetic fuel plants on a national basis would be small compared to direct combustion sources.

- The discussion of impacts resulting from use of a 200-mile buffer radius needs to be greatly expanded. If 100 percent of the Northern Great Plains and Four Corners coal and oil shale areas will be severely or completely restricted because of Class I constraints, this fact needs to be emphasized because of its disastrous impact on the nation's energy supply. Such a result must be fully explained in the text.

- The report quotes an Oak Ridge National Laboratory study indicating that the Bureau of Land Management wilderness program will have little impact on future development of coal resources. This is simply not true. Since designated wilderness areas would be prime candidates for Class I air quality redesignation, the impact could be very great.

- The 1979 SRI analysis is quoted as finding that "the Northern Great Plains are relatively free of federal lands." This statement appears inaccurate since the report definition of Northern Great Plains includes Montana and Wyoming, which contain extensive federal lands.

- The section on coal mining environmental impacts paints an overly bleak picture of the impacts of surface coal mining; e.g., "creates vast wastelands." It is suggested that a more balanced approach be taken; after all, it is estimated that extraction of coal, our greatest national energy resource, will disturb approximately 0.0035 percent (125 square miles) of the U.S. surface area per year. Furthermore, all new surface mining must conform to strict regulations, which will return the lands to other productive use after coal is removed.

RECOMMENDATIONS FOR FUTURE EFFORTS

While the need for additional reports is questioned, the NPC recommends that, should additional reports be undertaken, the scope of the analysis be briefer, issue-oriented, or site specific, rather than all-inclusive. A separate analysis should be made for each technology: oil shale, coal conversion, and biomass. Separate analyses would avoid the treatment of dissimilar problems as equally critical, and a clearer knowledge would be gained of the particular needs of each technology.

Factors that are site specific should not be treated in generalities, but by individual discussion of the magnitude and significance of each factor, delineating all critical factors in an itemized and complete manner.

Further, all coal conversion projects should not be treated together. Modified in situ and in situ oil shale projects should also be treated separately. The various environmental considerations should then be discussed as applied to each separate technology. Where there are various state laws that have a further impact on development, further analysis by state should be presented.

Issues of Importance

In writing an analysis that will affect the development of a critical industry, care must be taken to assure that the dynamic nature of the factors that influence that development is properly and completely identified. Regulations have been constantly changing, and the technologies have been steadily developing; these two important factors must be taken into account.

Changing Regulatory and Legislative Framework

Not only are some of the regulations that affect synthetic fuels in the formative stage, uncertainty also exists because of the possibility of new regulations or revision of regulations as mandated by law as in the case of the Clean Air Act.

A presentation of an overview of the necessary regulations governing the development of synthetic fuels would review those regulations that are currently in place and could address those not yet formulated. An overview of the National Environmental Policy Act, Clean Air Act, Resource Conservation and Recovery Act, Toxic Substances Control Act, Surface Mining Control and Reclamation Act (where applicable), and Clean Water Act would establish the basis for necessary action required for the development of a particular technology.

Further restrictions to energy development have been applied by state and local regulations. These can only be dealt with in a site-specific manner. They also need to be treated, together with an analysis of state and local cooperation, with national requirements. EPA's priority energy projects permitting process, and Colorado's Joint Review Process, and other state permitting processes need to be described.

Once the regulatory framework is defined, the subsequent logical step in the analysis is the determination of data available to meet those regulations.

Technical Considerations

Extensive work has been performed by developers of processes of the various technologies. Where available, these data should be

used as the primary data for the report. In addition, DOE and EPA have published extensive reports containing available data. Other sources for data include, but are not limited to, the following:

- DOE reports for each project sponsored by DOE
- Environmental Impact Statements
  - Environmental Reports
- EPA
  - Industrial Environmental Research Laboratory Reports
  - Pollution Control Guidance Documents
  - EPA's Priority Energy Project Tracking System Status Reports
- Library of Congress Research Service
- National Technology Center
- Bureau of Mines
- National Institute for Occupational Safety and Health
- Area Oil Shale Supervisor Office
- American Petroleum Institute
- Rocky Mountain Oil & Gas Association
- State sources such as:
  - Siting Commissions
  - Permit Applications
  - Land Mine Reclamation Boards
- Synthetic Fuels Data Handbook.

A number of processes have ongoing programs to determine data available from plants currently in operation. EPA has had a monitoring program of the Kosovo coal gasification plant underway and additional monitoring had been planned at Kosovo for the Tennessee Valley Authority (TVA) medium-Btu plant.

In the case of emissions, specific processes in each technology must be addressed singularly and not in unison. Pressure, temperature, and feedstock variation can cause changes in the product of a single process. Consequently, dealing in generalities should be avoided and specifics addressed as completely as possible.

Recognizing this, EPA attempted to determine the need for guides for the synthetic fuels industry and began preparation of Pollution Control Guidance Documents, which are to have two key

purposes: to aid permit writers in preparing realistic, comprehensive permits for the energy industry by describing and characterizing projected waste discharges from the various energy technologies under development and by providing the best possible information on the expected cost and performance of the variety of control options that appear applicable; and to provide guidance to the energy industry itself regarding the kinds of environmental impacts of concern to EPA for each kind of facility, the control options that EPA has deemed to be potentially applicable, and EPA's projections of probable cost performance of the various options.

As planned in early 1981, each Pollution Control Guidance Document will consist of three volumes. Volume I will be a summary report including recommended pollution control technology options and related costs; Volume II will be a detailed report describing pollutants, waste streams, and alternative control options, including cost and performance; and Volume III will be an appendix providing the data base for stream and pollutant characterization and control costs and performance. Although the actual issuance of these documents has been delayed and they may not be issued at all, the EPA staff has accumulated considerable information on pollution control options for the synthetic fuels industry. This information will presumably be available as a reference and data source and should be utilized in future reports.

Health and Safety Considerations

Since the health and safety issues will be some of the most important and difficult to be confronted and solved by industry, government, and the public, future reports should focus directly on these problems in a separate section devoted to them. More attention should be directed toward the importance, uncertainties, and potential impacts of health-related concerns. Discussion of the health issues associated with synfuel development could probably be done most conveniently by focusing on the people affected and on the statutes that can be used to regulate the industry.

Hazardous substances are safely manufactured and used in related industries. Related technology that could be used in the synthetic fuels industry should be discussed. While many aspects of the synthetic fuels industry, its products, and its processes are similar to or the same as those found in other industries, there are certain to be some differences. Further, since the combination of products and processes is unique, the continuing nature of the health and safety evaluation process should be discussed. While some potential problem areas can be identified, controlled, and regulated as plants are built and the industry is started, future reports should recognize that new, unexpected problems can arise and thus should focus on the need for continuous re-evaluation. Such an ongoing program exists in other industries and is to be expected in the synthetic fuels industry.

The National Institute for Occupational Safety and Health has contracted for comprehensive industrial hygiene surveys, which

should be addressed. Battelle Pacific Northwest Labs has completed and is continuing programs in this area. Los Alamos Scientific Lab has an Integrated Oil Shale Health and Environmental Program underway. Pittsburgh Energy Technology Center and Air Products and Chemicals, Inc. have conducted related studies also. Results of these efforts should be reviewed and included in any future analysis. The EIS for specific projects are a source of what is underway and what has been completed in these areas.

Assessment of Risk

If the future reports are to function as primary information sources, it would be helpful if they contained a list and/or description of the areas of the synthetic fuels industry likely to present the most significant risks. The report could then focus on alternative mechanisms for controlling them. Ideally, a method for analyzing both risks and benefits would be the starting point. The difficulty of such a formal analysis is recognized, but even an attempt at such an analysis would prove useful.

Since the synthetic fuels industry is by comparison to other American industries a new endeavor, the opportunity exists to collect information from an early stage. Thus, any future DOE reports should include a section on data collection, such as monitoring and testing results, and analysis. This section should include a description of "state of the art" testing and monitoring and any recommendations about how such testing, monitoring, and/or analysis should be done.

Socio-Economic Analysis

Cumulative effects of developing more than one project in an area can have large socio-economic impacts, especially in the case of oil shale development. A considerable amount of work has been done by individual companies to mitigate these impacts and should be included. Good sources of the socio-economic aspects of development are the EIS or Detailed Development Plans for a specific project. Once more, site-specific treatment is absolutely necessary for realistic analysis.

DOE and EPA Coordination

Memos of understanding between DOE and EPA illustrate their cooperation in the synfuels area. These efforts will reduce administrative constraints to the development of the synthetic fuels industry, but further cooperation is necessary. Specifically, DOE and EPA should provide the public with accurate information and access to available data which would be of help to the developing industry.

Future Reports

Table D-1 outlines the NPC's suggested format for any similar report of the synthetic fuels industry and its environmental considerations conducted in the future.

TABLE D-1

Suggested Format for Report on
Synthetic Fuels and the Environment

I. Summary
  A. Scope of Analysis
  B. Technology Analysis
  C. Control Costs
  D. Regulatory Analysis
    1. Research and Monitoring to Support Regulations
    2. Siting Impacts
  E. Environmental Impacts Analysis
  F. Permit Timing
  G. Specific Findings

II. Study Description
  A. Purpose of the Study
  B. Scope and Methods of Analysis
    1. Technologies Considered
    2. Assumptions
  C. Information Differences
    1. Regulatory Analysis
    2. Technology Analysis
    3. Siting Opportunities Analysis
    4. Permitting Opportunities Analysis
  D. Limits of Study Scope

III. The Technologies and Their Environmental Concerns
  A. Introduction
  B. Oil Shale
    1. Surface Oil Shale Retorting
    2. Modified In Situ Retorting
    3. In Situ Retorting
    4. Major Environmental Concerns
  C. Coal Conversion
    1. Direct Liquefaction
    2. High and Medium Btu Gasification
    3. Low Btu Gasification
    4. Major Environmental Concerns
  D. Biomass Conversion
    1. Ethanol From Grain
    2. Methanol From Wood
    3. Major Environmental Concerns
  E. Urban Waste
    1. Major Environmental Concerns
  F. Product Upgrading
  G. Emissions Data (Results of Monitoring Studies, Wherever Possible)
    1. Surface Oil Shale Retorting
    2. Modified In Situ Retorting
    3. In Situ Oil Shale Retorting
    4. Direct Liquefaction

        5. High and Medium Btu Gasification
        6. Low Btu Gasification
        7. Ethanol From Grain
        8. Methanal From Wood
        9. Urban Waste

IV. Regulatory and Legislative Analysis
    A. Resource-Oriented Laws and Regulations
        1. Oil Shale
            a. Prototype Leasing Program
            b. Permanent Leasing Program
        2. Coal
            a. Federal Leasing
            b. PSD Permitting
            c. Surface Mine and Reclamation Act
        3. Ecological Concerns
            a. Forest Service Wilderness Program
            b. Bureau of Land Management Wilderness Program
    B. General Permit Requirements
        1. National Environmental Policy Act of 1970
        2. Clean Air Act
            a. PSD Increments
            b. Class I Areas
            c. New Source Performance Standards
            d. Best Available Control Technology
            e. Lowest Achievable Emission Rate
        3. Clean Water Act
            a. Coal Conversion Facilities
            b. Oil Shale
            c. Biomass Water Quality Concerns
            d. Western Rivers Salinity Levels
            e. Water Quality Siting Opportunities Constraints
            f. The Overall Water Siting Constraints Analysis
        4. Occupational Safety and Health Act
        5. Mine Safety and Health Act
        6. Federal Hazardous Substance Act
        7. Toxic Substances Control Act
        8. Resource Conservation and Recovery Act
        9. Pollution Control Guidance Documents
        10. Potential Regulatory Issues
            a. Carbon Dioxide Global Impacts
            b. Acid Rain and Other Long-Range Transport Impacts

V. Health and Safety Analysis
    A. Oil Shale
        1. Hazards Identification
        2. Risk Assessments
        3. Monitoring Studies
        4. Programs
    B. Coal
        1. Hazards Identification
        2. Risk Assessments
        3. Monitoring Studies
        4. Programs

- C. Biomass
    1. Hazards Identification
    2. Risk Assessments
    3. Monitoring Studies
    4. Programs

VI. Environmental Impacts Analysis (Site-Specific Assessments)
- A. Summary
- B. Selection of Resource and Site-Specific Areas
- C. Regional Assessment Areas
- D. Oil Shale
    1. Leasing Opportunities
    2. Site-Specific Examples
- E. Coal
    1. Federal Land Management Siting Opportunities Analysis
    2. Land Unsuitable Criteria (for Surface Mining)
    3. Agricultural Lands
    4. Site-Specific Examples
- F. Air Quality Analyses
    1. Modeling Conclusions
    2. Supporting Air Quality Analysis
- G. Air Regulations and Regional Impacts
    1. Siting Opportunities Analysis
    2. PSD Class I Areas
    3. Coal Mining Impacts
    4. Summary
- H. Water Allocation
    1. Summary
    2. State Allocation Description
    3. Water Availability Requirements
    4. Western Coal and Shale Regions
    5. Water Supply Alternatives
    6. Water Analysis for Siting Opportunities Constraints
- I. Permit Consolidation
    1. Environmental Protection Agency
    2. State Consolidation
    3. Interstate Concepts
- J. Transportation Issues

VII. Socio-Economic Analysis
- A. Community Growth and Change
    1. Impacts of Growth -- Primary Work Forces
    2. General Population Increases
    3. A Technology Example of Induced Community Growth
    4. Factors Affecting Population Inflow
    5. Effects on Public Services
    6. Estimating Regional Absorption Capacity
    7. Regional Analysis
    8. Socio-Economic Findings
- B. State Problems
- C. Local Problems

Executive Summary
U.S. Arctic Oil and Gas

(This appendix is reprinted in its entirety
from the 1981 National Petroleum Council report, *U.S. Arctic Oil and Gas.)*

PREFACE

On April 9, 1980, the National Petroleum Council (NPC), a federal advisory committee to the Secretary of Energy, was requested by the Secretary to undertake a comprehensive study of Arctic area oil and gas development.

In requesting the study, the Secretary of Energy specified that:

> . . .the study should includ : resource assessment information: an engineering economic analysis for exploration, development, and production activities: a state-of-the-art presentation on the adequacy of available recovery technology and prospects for innovative technology required by the harsh Arctic climate: an assessment of the environmental impact of Arctic oil and gas operations and of the available mitigating measures: a comprehensive review of the adequacy of the existing oil and gas transporta tion infrastructure and proposals for improving this situation: and a discus sion of any international jurisdictional questions that may affect Arctic area development.

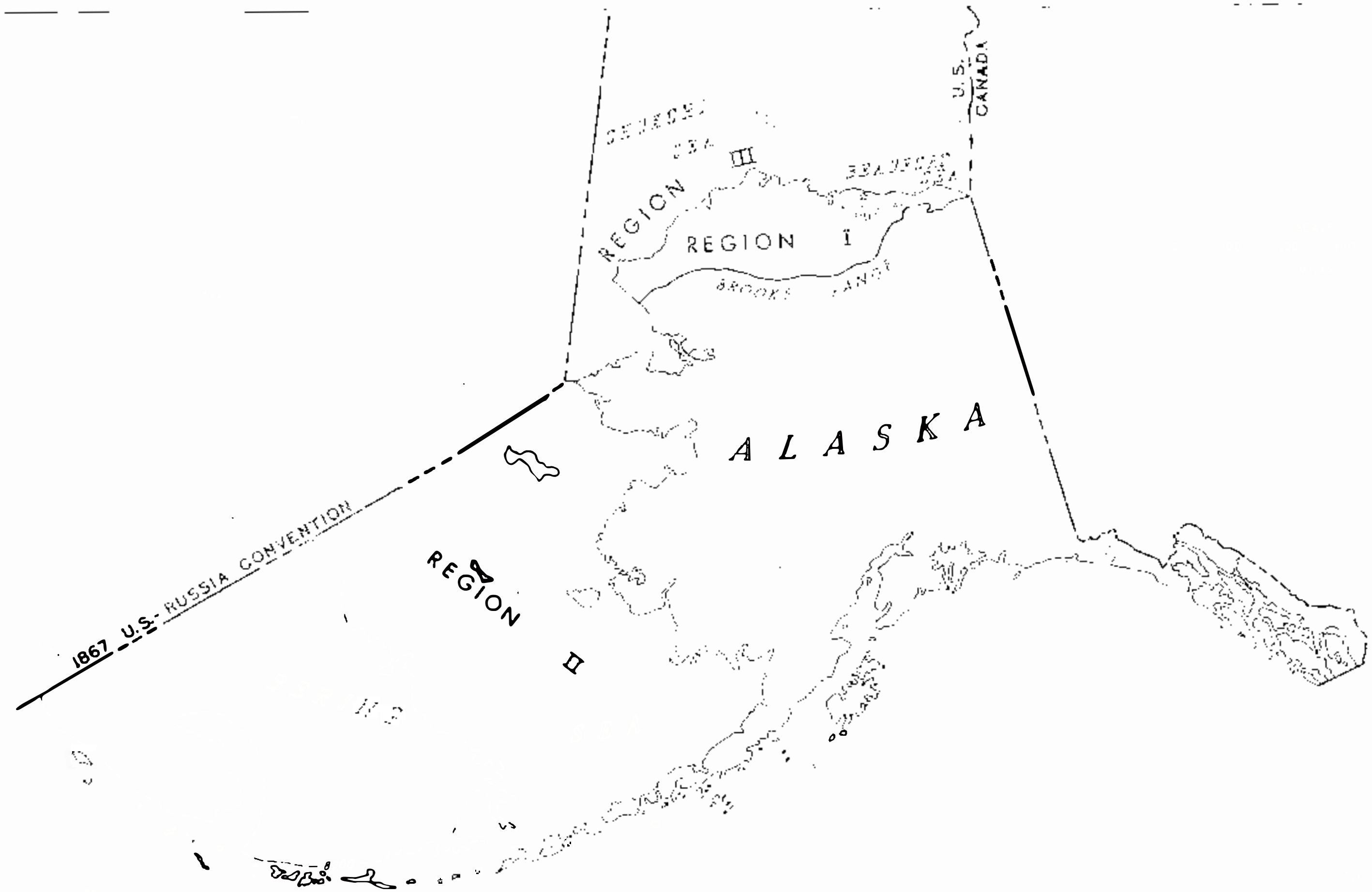
The complete text of the Secretary's request letter and a description of the National Petroleum Council are provided in Appendix A.

To assist in its response to the Secretary's request, the NPC established the Committee on Arctic Oil and Gas Resources under the chairmanship of Robert O. Anderson, Chairman of the Board, Atlantic Richfield Company. Hon. Jan W. Mares, Assistant Secretary for Fossil Energy, U.S. Department of Energy, served as Government Cochairman of the Committee. The Committee established a Coordinating Subcommittee and seven Task Groups to provide coordination and technical advice for the Committee. Rosters of these study groups are included in Appendix B. The broad membership of these groups includes representatives of both major and independent petroleum-related companies: federal, state, and local governments: the academic community: the environmental movement: organized labor: consultants: and Alaskan native organizations. As might be expected with such a diverse membership, all participants do not necessarily endorse each finding and recommendation: however, this report represents a consensus of the participants' views.

Geographic Area of the U.S. Arctic

In discussions with representatives of the U.S. Department of Energy during the early stages of this study, the Arctic area referenced in the Secretary's request letter was defined as seabed and subsoil under the resource jurisdiction of the United States north of the Aleutian Islands offshore and land territory north of the Brooks Range onshore. Accordingly, the terms "U.S. Arctic" and "Alaskan Arctic" as used in this report include the Bering Sea, a sub-Arctic region.

Due to differences in physical environment, operational requirements, and industry's expertise in the Arctic, three geographic regions, as shown in Figure 1, were defined for the purposes of this study.



NOTE: The United States has not fully resolved its Continental Shelf boundaries with other states concerned The lines on this map are for purposes of illustration only and do not necessarily reflect the positions or views of the United States with respect to the boundaries involved.

Figure 1. Regions Studied.

Region I, onshore Alaska north of the Brooks Range, is composed of the coastal plains and the foothills of the Brooks Range. Region II, the Bering Sea, includes a broad continental shelf less than 650 feet (200 meters) in water depth; however, the southwest portion of the region falls off rapidly to extreme water depths. This region is characterized by seasonal ice and severe storms. Region III, the offshore area north of the Bering Strait, includes the Beaufort and Chukchi Seas. This region also has a continental shelf that falls off gradually to 650 feet in depth and more rapidly to greater depths. The majority of this region is characterized by multi-year ice with ice ridges that may reach a thickness of 150 feet (45 meters), although the area very near the coast may be ice free for as much as three months a year.

Task Groups

Seven Task Groups were established to provide specialized expertise for the development of this report. Experts in the areas of jurisdictional issues, resource assessment, exploration, production, transportation, environmental protection, and economics provided the data and support for this report.

The Jurisdictional Issues Task Group defined, for the purposes of this report, the territorial and seabed and subsoil limits of the United States in the Arctic area, applying principles embodied in international agreements and in the Draft Convention on the Law of the Sea. The Task Group also identified areas of state/federal dispute, native claims, and land withdrawal that may affect oil and gas operations in the Arctic.

The Resource Assessment Task Group made estimates of the conventionally recoverable undiscovered oil and gas resources in the Arctic, utilizing the expert opinions of 17 organizations or individuals that responded anonymously to the NPC Assessment of Arctic Oil and Gas Potential questionnaire. An independent public accounting firm aggregated the survey results for 20 geologic, geographic, or jurisdictional areas. Using Monte Carlo techniques, the Task Group provided resource assessments for the total Arctic area and the three regions previously described.

Petroleum operations in the Arctic were examined by three Task Groups: Exploration, Production, and Transportation. Each of these Task Groups developed a comprehensive review of all factors related to Arctic operations, especially the limitations of conventional methods and the opportunities for the development of innovative techniques to be used in the Arctic. These Task Groups also developed cost data on Arctic operations and examined the effect of the Arctic environment on the timely development of oil and gas resources.

The Economics Task Group utilized the output from the other Task Groups to determine the economic attractiveness of selected areas and to calculate their economically attainable resources. In addition, the sensitivity of these results to changes in key parameters such as timing were evaluated, and total capital requirements were estimated.

The Environmental Protection Task Group examined the physical and biological environment in which petroleum operations may occur, noted the effect these operations may have upon the environment, examined the risk avoidance and mitigation techniques that can be employed to protect the Arctic environment, and identified environmental data needs. In addition, the impact of operations upon Alaskan native populations as well as legislative and regulatory constraints to oil and gas development were studied.

The work of these seven Task Groups is the basis for this report and many of their findings have been incorporated into it. The working papers submitted by the individual Task Groups for the use of the Coordinating Subcommittee are available from the office of the National Petroleum Council. A listing and abstracts of these working papers are presented in Appendix G.

Findings and Recommendations

Findings

It is the Council's judgment that oil and gas production from undeveloped areas in the U.S. Arctic could make a significant contribution to the nation's future energy supply. This judgment is based on the analyses set forth in this report and on the expertise of the study participants, and is supported by the following findings:

- ***Substantial undiscovered oil and gas resources are believed to exist in the Arctic regions of the United States***. The total potentially recoverable undiscovered oil and gas resources in the U.S. Arctic are estimated to be approximately 24 billion barrels of oil and 109 trillion cubic feet of total gas, or a total of 44 billion barrels of oil and oil-equivalent gas. It is also estimated that there is a 1 percent probability that the total undiscovered recoverable resources in this area could exceed 99 billion barrels of oil and oil-equivalent gas; there is an estimated 99 percent probability that the total undiscovered recoverable resources will exceed approximately 13 billion barrels of oil and oil-equivalent gas. These resources constitute a significant portion of total U.S. undiscovered oil and gas. It is felt that the Arctic Slope and the Bering, Beaufort, and Chukchi Seas all contain basins with significant promise.

- ***The basic technology is available to safely explore for, produce, and transport oil and gas in most of the U.S. Arctic***. Industry experience in the North Slope area, Cook Inlet, Gulf of Alaska, Canadian Arctic, North Sea, and in other cold, hazardous, or deep-water areas provides the basis for the design, construction, and operation of systems in Arctic regions. Proven technology exists for onshore operations. Proven technology and sufficient information and technical expertise for advanced design work is available for the industry to proceed confidently with operations in water as deep as 650 feet in the southern Bering Sea and to about 200 feet in the more severely ice-covered areas of the northern Bering, Chukchi, and Beaufort Seas. These capabilities will allow development of prospective areas in all of the northern Bering Sea, most of the southern Bering Sea, and well out into the ice-covered areas of the Chukchi and Beaufort Seas.

- ***Long lead times are required prior to production in the Arctic because of its harsh climate, remote location, and the large scale of the projects***. Depending on the location, at least 9 to 14 years will be required for planning, permitting, exploration, development drilling, design work, facility construction, and transportation system construction. These timing projections are felt to be near the minimums under improved business and regulatory conditions; even in an emergency, development could be accelerated by only a few years because of the unalterable physical obstacles.

- ***Economic analyses indicate that it will be attractive for industry to develop U.S. Arctic oil and gas if sufficiently large resources are found to support the costly development, production, and transportation systems that are***

required to operate in the region. Oil and gas operations in the hostile environment of the remote Arctic regions will be much more costly than those experienced in other climates. A significant cost associated with developing large resource volumes will be the major new transportation systems. either marine or pipeline. required to move the oil and gas to the market. Based on the assumptions used in these analyses. it appears that 18 to 21 billion barrels of the 24 billion barrels of potentially recoverable undiscovered oil will be economically recoverable. Of the 109 trillion cubic feet (TCF) of potentially recoverable natural gas and natural gas liquids. 68 TCF is non associated and 41 TCF is associated. i.e.. produced with oil from the same reservoir. Under the assumptions used in these analyses. 10 TCF of non-associated gas will be economically recoverable. At a 10 percent rate of return criterion. more than 22 billion barrels of oil and oil-equivalent gas are estimated to be economic. Certain key assumptions made and bases established in these economic analyses must be kept in mind in interpreting the economic findings since they have significant effects on the analyses and could yield low-side estimates. In this study. the more complex economics of associated gas were not evaluated. nor were the economics of the incremental use of the Trans-Alaska Pipeline System or the proposed Alaska Natural Gas Transportation System considered. The volume of economically recoverable gas would likely increase substantially if existing or planned production and/or transportation systems are in place and available at the time of development. since the analyses assume grass roots investments are required for all oil and gas production and transportation.

Some individual companies. utilizing their own internal assumptions and assessments. have considerably more optimistic estimates of economically recoverable gas. An optional portion of the NPC resource assessment survey requested participant estimates of the economically attainable resources. Limited responses suggest that 14 billion barrels of oil. 34 TCF of non-associated gas. and 20 TCF of associated gas. or a total of 24 billion barrels of oil and oil-equivalent gas. would be economically recoverable. This total is very similar to that obtained by the detailed analyses in this report.

- ***Pre-exploratory resource assessment or economic analysis, while useful, should not be given undue weight in the decision to open a basin for leasing***. Until a considerable amount of exploratory drilling is conducted in each and every basin. any assessment of potential resources or economically recoverable resources and whether the resources will be oil and/or gas must be taken as a preliminary estimate.

- ***Several promising sedimentary basins extend across international boundaries both to the east and to the west***. The boundary with the Soviet Union is defined by the Convention of 1867: no agreement exists as to the continental shelf boundary with Canada. No promising areas were identified beyond the seabed and subsoil under the resource jurisdiction of the United States as they are defined by the Draft Convention on the Law of the Sea.

- ***Year-round oil and liquefied natural gas tanker operations to ports south of the Bering Strait are feasible and practical***. In severe ice areas north of the Bering Strait. year-round tanker operations can probably be established. but the ability to maintain a continuous uninterrupted schedule is uncertain. Significant interruptions of tanker arrivals would require additional facilities if continuous production from a field is to be maintained. The cost of these facilities or the loss of revenues resulting from production cutbacks would reduce the amount of economically recoverable oil and gas in marginal areas.

- ***Many benefits can accrue to Alaskans from the oil industry's activities in their state***. Some of the income from lease sales. royalties. and taxes will provide additional support for government programs. Industry operations have provided employment. a source for emergency medical aid. and communications. Industry personnel and equipment have been used for rescue operations. and company personnel are usually active in their local communities.

- ***Native interests exert an important influence over oil and gas development in the Arctic.*** Through their native owned corporations, Alaskan natives control more than 40 million acres of land throughout Alaska that they wish to see developed in a manner that will meet their social and financial goals. Subsistence activities, particularly hunting and fishing, are of vital importance in preserving their cultural heritage and integrity. The oil and gas industry must be responsive to these interests.

- ***Impacts from oil and gas development on the lifestyle of the Alaskan native population can be anticipated, managed, and made beneficial by improvements in communication among all parties involved and by careful long-term joint planning.*** It is in both the communities' and industry's best interests to develop good practical planning capabilities in order to prepare for future petroleum developments. Such planning is necessary to help alleviate citizen concern about their lifestyle and livelihood and to maximize opportunities for these citizens resulting from the development activities while avoiding adverse impacts.

- ***The Arctic environment is important and sensitive, but impacts from the development of oil and gas resources can be minimized or avoided.*** The ecology in this region, both onshore and offshore, is important. Although accelerated activities in undeveloped areas will require an extension of existing information and technology, no problems are perceived that are beyond the demonstrated capability of the industry to solve. Prudent designs and methods of operation will allow oil and gas development to co-exist with commercial fisheries, recreational activities, and subsistence needs that are dependent on biological resources.

- ***A complicated regulatory system created by federal, state, and local governments to control oil and gas activities has delayed and added to the cost of Arctic oil and gas development.*** This system is made more complex by overlapping jurisdictions, by limited coordination between agencies, and by the lack of a clear federal policy regarding Arctic development. There appears to be unanimous agreement by all affected parties that this regulatory system needs to be redesigned.

Recommendations

To assist the nation in realizing the oil and gas potential of the U.S. Arctic, the federal government should implement and maintain a clear, comprehensive policy for Arctic oil and gas development. This policy should be responsive to the national need for domestic resources, consistent with national energy policies. Expedited development of oil and gas resources and multiple use of Arctic lands, both onshore and offshore, should be an integral part of this policy, consistent with local needs and concerns. State and local governments should be encouraged to support this policy. Accordingly, the Council makes the following specific recommendations:

- ***A stable lease schedule offering federal Arctic lands for private exploration and development should be established, with all areas both onshore and offshore having oil and gas potential included in the schedule.*** Areas with the greatest potential should be scheduled for early leasing. Scheduled lease sales need not be delayed until comprehensive information on physical and biological environmental conditions is available, or until specific site information is available; such information can be developed well in advance of any significant onsite work. Adequate provisions exist under present law to allow withholdings of tracts with potentially significant environmental problems until mitigating measures are developed.

- ***The leasing system should be made responsive to the unique conditions encountered in the development of oil and gas in the U.S. Arctic.*** Each lease sale should include a sufficient amount of acreage to justify necessary operating systems. Acreage offered for the first sale in a frontier area should cover all major exploration prospect features in the entire basin or area of interest so as to expedite the evaluation of prospective areas. The primary lease term for Outer Continental

Shelf leases should be at least 10 years because remote operating areas combined with hostile climate require lengthy lead time preparations. An automatic "suspension of production" provision should become a part of leasing policy so that marginal discovered resources can be retained by the lease owner until economic transportation can be justified.

- ***A comprehensive exploratory drilling effort extending to all areas thought to have undiscovered resources should be undertaken by industry to define the true oil and gas potential of the U.S. Arctic.*** Several resource assessments of the type prepared for this report have been completed by others. Additional similar analyses will not enhance real knowledge of the region's resources until the promising areas have been leased and tested by drilling, and important new data have been obtained.
- ***A specific existing agency should be designated the responsibility for expediting permitting actions in the Arctic.*** A common procedure should be established to ensure that both its own permits and those of other involved agencies are expedited. The most important way to accelerate and improve efficiency is to streamline and simplify the laws and regulatory processes relating to leasing and permitting. Overlapping responsibilities of regulatory agencies should be eliminated. Such changes would allow government to be more pragmatic in its decision making. Statutes and procedures that unnecessarily delay operations or are not applicable to the Arctic should be modified or eliminated. Deadlines should be set for procedural requirements and for approvals. Such initiatives should be aimed at expediting energy development while fully responding to substantive environmental and socio-economic needs.
- ***Government agencies with legislated responsibilities for conducting operations in support of exploration, production, and transportation activities in the Arctic should be organized and staffed to meet in a timely manner those responsibilities.*** Some of these responsibilities include search and rescue, oil spill surveillance, weather and ice forecasting, structure accreditation, vessel inspection, preparation of environmental impact statements, and surface and air navigational aids.
- ***Continued private and public Arctic research is important to the national interest and should be encouraged and supported where necessary.*** Research and development in Arctic technology for operations in hostile environments will lead to evolutionary improvements in operating systems. Efforts to enhance knowledge of ice conditions, ice properties, and ice forces should be stressed. Biological research and monitoring should be continued. Federally funded research programs should focus on collection and characterization of fundamental data and testing programs of broad issue. Timely and rapid dissemination of information obtained by government agencies should be required.
- ***The federal and state governments should provide necessary assistance to local communities and governments in understanding and planning for the community development that will evolve with oil and gas development.*** Particular attention should be given to determining the most efficient means of funding comprehensive and continuous planning efforts.
- ***Sources of funding should be identified for government and community programs and activities related to development of oil and gas in the U.S. Arctic.*** Both lease sales and production royalties provide substantial sources of funds directly attributable to oil and gas industry activities. A portion of these direct revenues could be used to ensure that appropriate governmental support is provided. Stability of funding is required for effective execution of these programs.

More detailed findings and recommendations can be found in the chapters of this report.

Summary

Arctic oil and gas exploration began in Alaska with the U.S. Geological Survey's (USGS) surface work in 1901. In 1904, oil seeps were found on what is now the National Petroleum Reserve-Alaska (NPRA). This 23.6-million-acre area was designated the Naval Petroleum Reserve Number 4 (NPR-4) by Executive Order in 1923, and some geological mapping occurred shortly ther aft r. From 1944 until 1953, the Navy, in conjunction with civilian drilling contractors, conducted an extensive geological mapping and exploratory drilling program on the NPR-4. Renewed government exploration in the NPRA was undertaken in the 1970s. Commercial quantities of oil and gas were not found.

During 1949 and 1950, in an effort to develop a natural gas fuel supply for the Navy's Barrow Camp, several test wells were drilled in the vicinity. These South Barrow wells were the first development wells drilled and completed in the U.S. Arctic. They furnished proof that hydrocarbons could be produced in the Arctic region.

In 1968, the Prudhoe Bay oil field was discovered east of the NPRA. After this field was discovered, two alternate transportation options were considered: tanker movement through the Northwest Passage, and pipelining across Alaska to an ice-free port. The pipeline option was chosen on the basis of reliability, and pipe was ordered. The design called for a 48 inch diameter line with a potential capacity of 2 million barrels per day, initially equipped to deliver 1.2 million barrels per day across an 800-mile route from Prudhoe Bay to an ice-free terminal in Valdez, Alaska.

Opposition to the pipeline by environmentalists and disputes over land ownership led to a series of legislative, environmental, and judicial hearings that delayed the start of construction for five years. Construction of the Trans-Alaska Pipeline System (TAPS) began in April 1974, and the pipeline was completed and went into service in mid-1977. Upon completion of TAPS, the field was placed on continuous production.

During the early 1970s an extensive research and development program was carried out by industry to solve the many problems associated with oil operations in the Arctic. The success of these programs is attested to by the fact that some 350 wells have been completed, and oil is being produced and transported at a rate of 1.5 million barrels per day. A total of approximately 2 billion barrels of oil have been moved to market as of the end of 1981. A second, smaller field, Kuparuk, is now being developed, and production is expected to commence in 1982.

Development of the Prudhoe Bay field and construction of TAPS and the Valdez terminal were conducted under the most rigorous design and quality control specifications ever imposed upon onshore petroleum operations. Successful operation of this system has been achieved and it represents a model for future land pipelines and terminals.

Resources

An evaluation of the potential oil and gas resources in the sedimentary basins of the U.S. Arctic was made based on a review of published information, USGS data, and a survey of the study participants. It was established that as of August 1980, 16.5 billion barrels of recoverable oil and oil-equivalent gas had been discovered on the North Slope of Alaska. Of this total, 10.2 billion barrels are oil and 35.4 trillion cubic feet (TCF) are gas. An additional 44 billion barrels of undiscovered recoverable oil and oil-equivalent gas resources are expected to be present in the Arctic. Of these total undiscovered resources, it was estimated that 24 billion barrels will occur as oil, and the remainder will consist of 109 TCF of gas and natural gas liquids. Of this gas total, 68 TCF are expected to occur as non-associated gas and 41 TCF should be associated with oil production.

Although there are at least 10 highly prospective areas, the largest resources are estimated to occur in the Beaufort Shelf and the Navarin Basin Shelf. It was also concluded that there is a 1 percent chance that the total quantity of undiscovered recoverable oil and oil-equivalent gas could exceed 99 billion barrels, and a 99 percent chance that it could exceed 13 billion barrels. These undiscovered resources may constitute as much as 40 percent of the total undiscovered recoverable oil and gas resources remaining within U.S. jurisdiction.

Basins appearing to have a low potential should not be ignored. Additional basic geological information could cause significant revisions, either upward or downward, in the estimates. Confirmation of these estimates can be achieved only by extensive leasing and exploratory drilling.

Technology

Large-scale Alaskan North Slope operations and extensive experience in the Cook Inlet, the Canadian Arctic, and the North Sea have demonstrated that, with an economic incentive, the petroleum industry can rapidly develop sufficient technology to safely conduct exploration, design and operate production facilities, and provide transportation in cold, remote, and ice-covered regions, both onshore and offshore. The fundamental techniques of exploration, production, and transportation in Arctic regions are not significantly different than those used elsewhere. The novel problem is the design and operation of systems that can cope with severe sea ice. Continuing research, development, and engineering programs will provide basic information and technology for successful site-specific designs. Technological advances that have the greatest economic potential relate to improving the ability to operate exploration, drilling, production, and transportation systems efficiently during all seasons. This requires coping with low temperatures, poor visibility, storm waves in the Bering Sea, and particularly, the extreme sea ice conditions in the Chukchi and Beaufort Seas.

Exploration technology in the Arctic requires that the usual geological techniques be modified to accommodate weather and specific environmental concerns, but no unique methods are needed or employed. The same is true for geophysical work, although seasonal considerations more generally control the use of heavy geophysical equipment on the tundra and affect the accessibility of offshore areas containing sea ice. The drilling of an exploratory well in the Arctic differs from drilling in other climates in that special techniques have been developed for drilling safely in permafrost areas. Offshore drilling sites must be located in areas free of sea ice or must have a platform or island as a drilling base able to withstand the moving pack ice. Remote locations make logistical support of operations very difficult. These considerations lead to substantially higher costs than those encountered in less hostile regions. Most of the future geological and geophysical technology that will improve exploration will not be Arctic-specific but will be applicable in all areas.

Production technology for Arctic regions requires similar considerations of weather and climate, especially in the design, construction, and installation of production facilities under adverse conditions. Installations and operations must be designed for permafrost, both onshore and in some offshore locations. Offshore structures for drilling, production, storage, and loading that will successfully resist sea ice are a major requirement. It should be

possible to develop safe designs for offshore production islands or platforms within the time period required to lease, explore, and delineate a major oil or gas find.

Additional information on sea ice and its associated problems is being obtained through research programs. These research programs should be continued, as they are needed to complete novel designs and will lead to more cost-efficient operations. Modular construction in temperate climates with transportation of large modules to the site is a proven method of reducing construction costs.

Transportation technology for oil in Arctic regions has been successfully developed for onshore pipelines, as demonstrated by TAPS. Marine transportation has not reached the same level of development. Appropriate tankers and icebreakers can be designed to provide year-round reliable operations to ports south of the Bering Strait handling either crude oil or liquefied natural gas (LNG). Marine vessel operations north of the Bering Strait appear less reliable, and there is a need for more icebreaker experience in this area before tankers are considered an attractive transportation system. Marine pipeline operations in the Arctic should be similar to operations in the North Sea and Cook Inlet, but will be more difficult and demanding because weather and logistics are more severe. As in the case of exploration and production, extended knowledge of the characteristics, conditions, and dynamics of sea ice is needed to optimize and ensure reliability in Arctic marine operations.

Economics

Limited economic evaluations of the Arctic oil and gas resources were made based on assessments of potential resources, costs, and schedules for operations developed in this study. These evaluations demonstrate that large reserves are required to support the high cost of oil and gas field development and associated transportation systems. When transportation systems can be shared by producing areas, significantly improved economics are obtained.

The economic resource base was calculated by combining the reserve evaluations with the resource assessments. Estimates of the capital investment required for exploration, production, and transportation facilities were developed and the sensitivity of the economics to various factors was evaluated.

In evaluation of the oil resources, the economic resource base analysis showed that when applying a 10 percent return as an investment criterion and deleting presently infeasible areas, the total risked mean assessment was reduced from 24 billion barrels to 21 billion barrels. At a 15 percent return it was reduced to 18 billion barrels of economically recoverable oil. The analysis indicates little opportunity for a 20 percent rate of return to be achieved. These results assume that grass roots investments are required for all oil production and transportation and that no incremental use of the TAPS line would be possible at the time of dev lopment.

Evaluation of non-associated gas resources showed that when applying a 10 percent return criterion the risked mean assessment of 68 TCF of potentially recoverable non-associated gas is reduced to 10 TCF of economically recoverable gas. In no case was a 15 percent rate of return shown to be achieved. No evaluation was made of the more complex economics of producing associated gas, which could improve the prospects of gas development. Gas transportation from the North Slope was evaluated only on the basis of transporting LNG by tanker from different ports. No case comparable to the proposed Alaska Natural Gas Transportation System (ANGTS) was developed, nor were evaluations of the economics of the incremental use of the ANGTS line developed. Use of this system could substantially increase the economically recoverable gas.

Although considerable variation was shown in the economics for different areas, the uncertainties inherent in estimating all factors in frontier basins, especially the undiscovered resource base, suggest that none of the prospective basins should be excluded from early leasing and exploration.

While benefits of oil and gas operations have been demonstrated, it is inevitable that substantial oil and gas development in the

U.S. Arctic regions will have some impact on rural Alaskan populations and on the surrounding environment. The experience of the petroleum industry in recent years demonstrates that such impacts can be managed in a beneficial manner with minimal adverse effects on the environment.

The Arctic area contains about 45,000 inhabitants located in six regional centers and about 60 small villages. This population is distributed ov r thousands of square miles along the northern and northwestern coasts of Alaska from the Alaskan/Canadian border through the Aleutian Islands. Because oil and gas development is likely to occur only at a few specific points, many of the native villages will not directly experience the impact of development. In the few communities that would be directly affected, expansion will occur in community truc ture, shoreline resources, local labor markets, and housing. Employment and business opportunities will evolve that could benefit those who choose to participate. In order to maximize these opportunities and minimize any adverse impacts, it is necessary to develop adequate long-term planning and good industry/native relationships.

Environmental impacts can be minimized or avoided in the Arctic by operating practices that have been and continue to be developed by the oil and gas industry in their operations throughout the world, particularly at Prudhoe Bay, the TAPS corridor, the Cook Inlet, the North Sea, and the Canadian Arctic. The Arctic environment is both fragile and biologically important; however, the risk of significant disturbance can be minimized. Accelerated activities in new geographic areas will require an extension of existing technology. However, no problems are perceived that are beyond the projected capability of the industry. As discoveries of oil and gas are made, additional site-specific data will be developed, and research, development, and information gathering will continue. With this information and a continuing commitment to good practices by industry, environmental im pacts should be negligible and oil and gas development can proceed safely and successfully in the Arctic.

Regulation

The complicated regulatory system that has been imposed on the industry needs a complete redesign with the permitting and leasing agencies operating under a clear federal policy to expedite Arctic development. Revisions in statutes, regulations, and policies at all levels of government are necessary to accomplish such a simplification. Specific recommendations for such revisions are made in this report.

ACRONYMS AND ABBREVIATIONS

4-AAP -- 4-aminoantipyrine method

ABA -- American Bar Association

ACEC -- areas of critical environmental concern

ANGTS -- Alaska Natural Gas Transportation System

APD -- Application for Permit to Drill

API -- American Petroleum Institute

AST -- activated sludge treatment

BACT -- Best Available Control Technology

BAT -- Best Available Technology Economically Achievable

BBOE -- billion barrels of oil equivalent

BCT -- Best Conventional Pollutant Control Technology

BIA -- Bureau of Indian Affairs

BLM -- Bureau of Land Management

BMP -- Best Management Practices

BOD -- biochemical oxygen demand

BOP -- blowout preventer

BPT -- Best Practicable Control Technology

Btu -- British thermal unit

CAFE -- Corporate Average Fuel Economy

CASAC -- Clean Air Scientific Advisory Committee of EPA's Science Advisory Board

CBA -- Cold Bed Absorption

CEQ -- Council on Environmental Quality

CER -- Categorical Exclusion Review

CERCLA -- Comprehensive Environmental Response, Compensation and Liability Act of 1980 (Superfund)

CLC -- Civil Liability Convention of 1969

CO -- carbon monoxide

CO_2 -- carbon dioxide

COD -- chemical oxygen demand

COS -- carbonyl sulfide

COST -- Continental Offshore Stratigraphic Test

CRISTAL -- Control Regarding an Interim Supplement to Tanker Liability for Oil Pollution

CS_2 -- carbon disulfide

CTG -- Control Technique Guideline

CZM -- Coastal Zone Management

CZMA -- Coastal Zone Management Act of 1972

DAF -- dissolved air flotation

DEIS -- Draft Environmental Impact Statement

DOE -- Department of Energy

DOI -- Department of the Interior

DOT -- Department of Transportation

DWT -- deadweight tons

EA -- environmental analysis or assessment

EIS -- environmental impact statement

EOR -- enhanced oil recovery

EP -- extraction procedure

EPA -- Environmental Protection Agency

FCCU -- fluid catalytic cracking unit

FEIS -- Final Environmental Impact Statement

FLPMA -- Federal Land Policy and Management Act of 1976

FWS -- Fish and Wildlife Service

GAO -- General Accounting Office

GNP -- Gross National Product

GRT -- gross registered tons

hp -- horsepower

H_2S -- hydrogen sulfide

IBLA -- Interior Board of Land Appeals

IMCO -- Intergovernmental Maritime Consultative Organization

JRP -- Joint Review Process for Major Energy and Mineral Resource Development Projects (Colorado)

KGS -- known geologic structure

LAER -- Lowest Achievable Emission Rate

LNG -- liquefied natural gas

LOOP -- Louisiana Offshore Oil Port

LORAN -- long range radio navigation

LOT -- load on top

LPG -- liquefied petroleum gas

MARAD -- Maritime Administration

MARPOL 1973 -- International Convention for Prevention of Pollution from Ships, 1973

MARPOL 1978 -- Tanker Safety and Pollution Prevention Convention, 1978

MB/D -- thousand barrels per day

MFP -- Management Framework Plan

mg/l -- milligrams per liter

MMB/D -- million barrels per day

MOU -- memorandum of understanding

MTA -- metric tons per annum

$\mu g/l$ -- micrograms per liter

$\mu g/m^2$ -- micrograms per square meter

NAAQS -- National Ambient Air Quality Standards

NaOH -- sodium hydroxide

NAS - U.S. National Academy of Sciences

NEPA -- National Environmental Policy Act of 1970

NESHAPS -- National Emission Standards for Hazardous Air Pollutants

NGL -- natural gas liquids

NH_3 -- ammonia

NO -- nitrous oxide

NO_2 -- nitrogen dioxide

NO_x -- nitrogen oxides

NOAA -- National Oceanic and Atmospheric Administration

NPC -- National Petroleum Council

NPDES -- National Pollutant Discharge Elimination System

NPR-4 -- Naval Petroleum Reserve Number 4

NPRA -- National Petroleum Reserve-Alaska

NRC -- National Research Council

NRT -- National Response Team

NSCP -- National Spill Contingency Plan

NSPS -- New Source Performance Standards

NTL-6 -- Notice to Lessees and Operator No. 6 Approval of Operations

NWPS -- National Wilderness Preservation System

O&G -- oil and grease

OCS -- Outer Continental Shelf

OCSLA -- Outer Continental Shelf Lands Act of 1953

OS&T -- offshore storage and treating

OSC -- On-Scene Coordinator

OTA -- Office of Technology Assessment

PAH -- polycyclic aromatic hydrocarbons

PER -- Preliminary Environmental Review

POD -- Plan of Development

POE -- Plan of Exploration

POTW -- publicly owned treatment works

ppm -- parts per million

ppmv -- parts per million volume

PSD -- Prevention of Significant Deterioration

psi -- pounds per square inch

psig -- pounds per square inch gauge

RACT -- Reasonably Available Control Technology

RARE -- Roadless Area Review and Evaluation program

RCRA -- Resource Conservation and Recovery Act of 1976

R&D -- research and development

RMP -- Resource Management Plan

RRT -- Regional Response Team

SCOT -- Shell Claus Off-Gas Treating

SIP -- State Implementation Plan

SMCRA -- Surface Mining Control and Reclamation Act of 1977

SO_2 -- sulfur dioxide

SO_x -- sulfur oxides

SOLAS -- International Convention for Safety of Life at Sea

SPCC -- Spill Prevention, Control and Countermeasure

Superfund -- Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

TAPS -- Trans-Alaska Pipeline System

TCF -- trillion cubic feet

TOC -- total organic carbon

TOVALOP -- Tanker Owners Voluntary Agreement Concerning Liability for Oil Pollution

TSP -- total suspended particulates

TSS -- total suspended solids

UIC -- underground injection control

ULCC -- Ultra Large Crude Carrier

USGS -- U.S. Geological Survey

VLCC -- Very Large Crude Carrier

VOC -- volatile organic compounds

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